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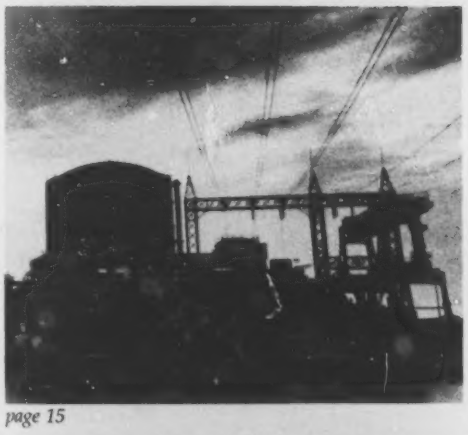

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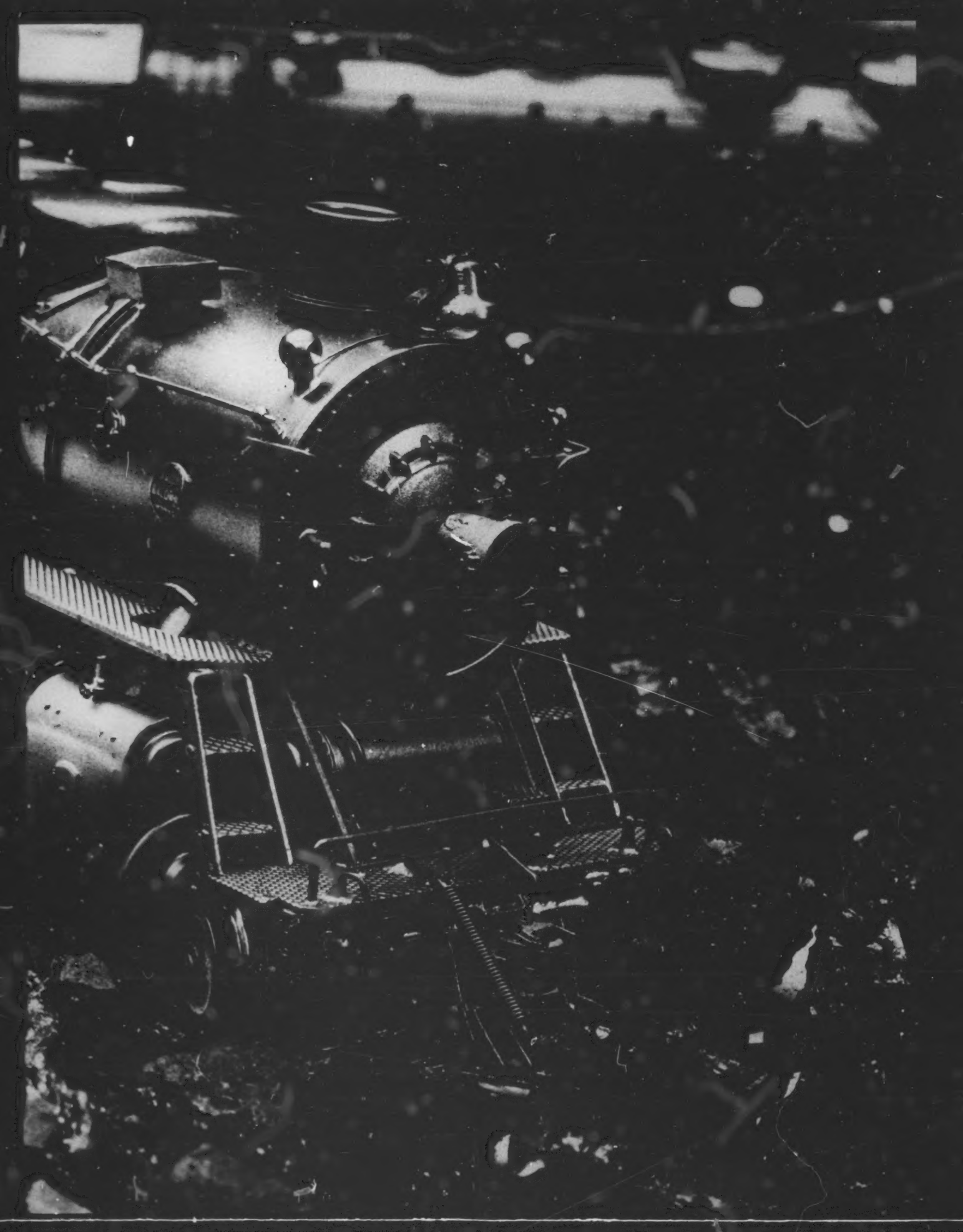
Interstate Commerce Commission rulings on allowable coal rates could cause the rates to quadruple in the next ten years.

Illustration by Michael J. McGurk



Are America's Electric Utilities Being Railroaded?

By Edward F. Mitchell

ICC rulings on coal freight rates could raise consumers' electric bills significantly.

Imagine a nation dependent on one fuel for more than half of its electricity. Then imagine that the majority of that fuel is transported by a single industry —a virtual monopoly. Finally, imagine that a government regulatory agency is making it possible for that fuel transporter to double its rates in five years, triple them in eight years, and quadruple them in ten.

The trouble with this "imaginary" scenario is that it's highly probable. The nation is the United States, the fuel is coal, the transporter is the railroad industry, and the government agency is the Interstate Commerce Commission (ICC).

To make the scenario even more incomprehensible, consider that:

1. Congress has specifically directed the ICC to protect captive shippers, such as coal-fired utilities;
2. the nation's energy policy specifically favors development of coal to help reduce dependence on foreign oil; and
3. the railroads are in strong financial condition, according to Wall Street experts, and are earning a greater profit margin on coal than on the other commodities they carry.

The discrepancy between how the ICC views the condition of U.S. railroads and the reality of their condition seriously concerns those who depend on rail freight transportation. If left unchecked, the ICC and the railroads may succeed in causing U.S. consumers to pay billions of dollars in higher electric bills and to become more dependent on foreign oil.

That the nation's energy and transportation policies would not be supported by the ICC may come as a surprise. Yet this is precisely what has been developing since the passage of the Staggers Rail Act three years ago. Since then the railroads have improved their financial condition substantially, but the ICC continues to treat them as a depressed industry. While giving lip service to balancing the needs of shippers, carriers, and the public, the ICC has been erecting a brand new structure of *regulation* that in fact denies captive shippers future protection from unrestrained monopolistic rate setting by railroads for coal transportation.

This was not the outcome of deregulation as envisioned by those who worked hard to write protection for captive shippers into the Staggers Rail Act of 1980. In the opinion of one Senator who did so, the intent of Congress "has been ignored," and the ICC "has virtually granted unlimited pricing freedom for coal movements and left captive coal shippers with little recourse before the Commission."[1]

To understand how the ICC has not abided by the intent of Congress requires a review of a few fundamental differences between the federal regulatory climate for rail rates and the state regulatory climate for utilities. At present, the ICC is accepting and even encouraging concepts of accounting, return on net investment, and revenue adequacy that would raise a storm of protest if presented before state commissions in justification of higher electric rates. Yet if these concepts are allowed to prevail, state regulatory commissions in their regulation of electric utilities will be faced with annual coal rail rate increases that could run as high as 15 percent above inflation.

New Standards of "Revenue Adequacy"

The Staggers Act, as explained by the Senate chairman of oversight hearings held on the legislation earlier this year, had three goals:

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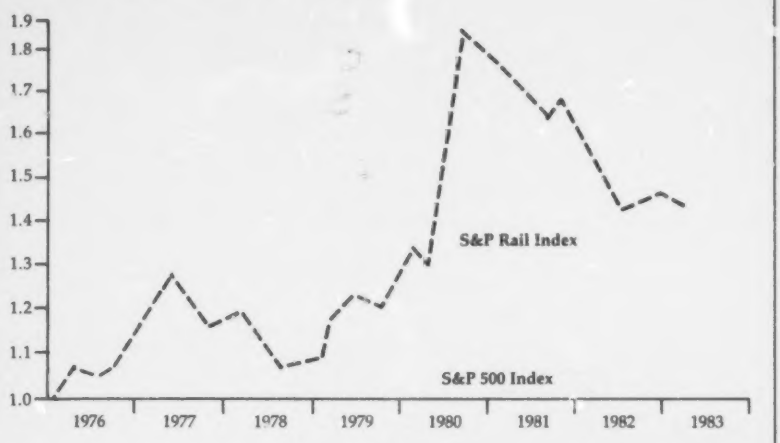
Figure 1
S&P's Rail Index v. S&P 500 Index



> . . . one, to improve the economic health of the railroad industry; two, to ensure effective competition; and three, to protect shippers through regulation in the absence of effective competition.[2]

The question raised by the Commission's rules for measuring the economic health of the railroad industry is whether or not they yield a picture that accords with the true balance sheets and operating statements of the railroads. The answer to this question is crucial. In defending its policy of granting railroads increasing freedom to raise rates on captive coal traffic, the ICC relies principally on one argument: the railroads are "revenue inadequate" and need every assistance to improve their financial health.

There are a number of problems with how the ICC arrives at its standard of revenue adequacy. As with utility regulation, the ICC measures revenues against an investment or rate base figure. Since Staggers, the gap between the allowable rates of return and the rails' performance, *as measured by the new ICC standards,* has grown. In its annual determination of revenue adequacy for 1983, the ICC found *all* of the nation's major railroads were "revenue inadequate" by a wide margin.[3]

Yet the month after the ICC issued that determination, *Traffic World* reported:

> If the railroad industry is still in the poor financial condition it has sustained during the past decade, the news has not reached investors and analysts on Wall Street.
>
> Spurred on perhaps by a deregulatory environment, railroad stocks have rewarded investors handsomely over the past 12 months. And railroad analysts on Wall Street . . . generally are optimistic about the future.[4]

Standard and Poor's Rail Index supports this evaluation. As shown in Figure 1, the rail index displays a consistently better performance than the S&P 500 Industrial Index.[5] The discrepancy between Wall Street's assessment and the ICC's is no mystery. If the allowable rate of return is viewed as the bridge or upper limit and revenues are the river underneath, the ICC has been simultaneously raising the bridge and lowering the river by changing accounting concepts.

Since Staggers, the ICC has "raised the bridge" by discarding the multiple criteria it previously used for determining revenue adequacy in favor of a single measurement—return on net investment, or ROI. By contrast, financial analysts use a multi-criteria approach to evaluate financial position—such as cash flow, long-term debt-to-capital ratios, and pretax interest coverage.[6] Moreover, the ICC will not determine a railroad's return to be adequate until it matches what the ICC calculates to be the costs the railroad would encounter in borrowing funds today.

Furthermore, the ICC so far has allowed railroads to "lower the river" by inflating expenses or understating revenues used in the ROI calculation. For example, if a railroad owns a fuel oil company from which it buys all of its diesel fuel, according to ICC accounting practices, the cost of the fuel from this captive fuel company is listed as an expense in the ROI calculation, but none of the revenues of the captive fuel company are included in the railroad's earnings report. Nor is the price the railroad is, in effect, charging itself for the fuel reviewed by the ICC for fairness.

Another questionable accounting method that favors the railroad is the ICC's treatment of deferred taxes, which amounts to a no-cost loan to a company from the U.S. Treasury paid for by U.S. taxpayers. By allowing railroads to include these funds in their investment base, the ICC permits the

railroads to earn a return on the amount of deferred taxes as if they had paid to borrow this money. No other regulated industry receives this benefit.

The railroads' income also is understated by the use of retirement/replacement/betterment accounting, commonly referred to as betterment accounting. When a railroad replaces track, the cost is treated like an operating expense instead of a capital improvement to be depreciated over a number of years. Thus, the full cost of replaced track is deducted in the current year, depressing earnings. Such beneficial accounting treatment is unique to railroads. If conventional depreciation had been used in 1978, for example, it would have increased the net income of a 10 railroad sample by 35 percent, according to a 1981 General Accounting Office study.[7]

To its credit, the ICC is taking steps to recognize some of the lost revenues from subsidiary investments that are transportation-related—like the captive fuel company illustration—but the railroads are circumventing the process by transferring ownership of subsidiaries to parent holding companies. Once again, the revenues are denied the railroad's ROI calculation, but the benefits still flow to the overall corporate structure.

At the same time that it is moving—albeit belatedly and incompletely—to bring railroad financial reporting more in line with conventional practices, the ICC is proposing another accounting change that will "lower the river" and more than offset its corrections to past distortions in railroad earnings reporting. In brief, the ICC is proposing to allow railroads to restate their investment base from the traditional "original cost" basis to a form of "current cost," or essentially, what it would cost to replace railroad facilities at today's costs.

On a current cost basis, the railroads' investment base, by the ICC's own estimates, would be almost quadruple the "original cost" base. Consequently, their return on investment would shrink to feeble levels despite rich cash positions, strong financial ratings on Wall Street, and billion dollar acquisitions.[8]

Mark Borchelt

Even prior to the issuance of coal rate guidelines, the growth of coal rates has outpaced that of other freight.

These selected examples illustrate the ingenuity of the railroads and the ICC in distorting true earnings and ROI figures. Unfortunately, those who would like to investigate other indicators of a railroad's financial condition are frustrated. The obstacle: the key information is held within railroad company records and the ICC has not seen fit to require complete disclosure.

Market Dominance

The ICC's liberal interpretation of allowable rates of return would not be cause for concern, in itself, if the railroads' desire to charge what the market will bear were constrained by competition. But nearly 60 percent of the coal consumed for electricity is delivered by rail, and 90 percent of utility plants dependent on rail are served by only one line and have no other means of delivering coal.

The Staggers Act was designed to lessen regulatory constraints on the railroads. However, it was also clearly

Mark Borchelt

In 1982, the utilities' coal rail bill was $5 billion. By 1992, it could approach $20 billion.

intended to provide for continued regulation of rates by the ICC when a carrier has "market dominance" over captive shippers.[9] Yet in ruling after ruling, the ICC has abandoned the nation's largest captive shipper—the electric utility industry and its customers. Instead of protecting the captive shipper from unreasonable rates, the ICC in effect has been *advocating* that the railroads charge captive shippers monopoly-based rates.[10]

One of the principal ways the ICC has eluded Congressional intent is to change the basis for determining when competition does or does not exist, i.e., whether a railroad has "market dominance." The importance of the market dominance test is that it determines if the ICC has jurisdiction to consider whether or not the railroad is charging an unreasonable rate. Under the Interstate Commerce Act, market dominance is measured on the basis of an absence of effective competition from other carriers or modes of transportation for the transportation to which a rate applies.[11] However, after the Staggers Act was passed, the Commission introduced the amorphous concepts of geographic and product competition, contrary to Congressional intent. Under these criteria, a railroad could be found *not* to dominate a market if evidence were presented to the Commission that the shipper could get the same products from other potential sources or ship them to other destinations or *could* buy an alternative product.

A three-judge panel of the Fifth Circuit Court of Appeals ruled in late 1982 that the Commission acted illegally in introducing these considerations. An ICC/railroad appeal to the full court awaits a decision. In this case, the utility industry, along with other shippers, argued that despite the ICC's assertion to the contrary, the Staggers Act provided no support for changing in any way the market dominance test.

Maximum Rate Standards

Recently, the ICC proposed a new "constrained market pricing" policy for determining what is a maximum reasonable rate for a captive utility coal shipper. Under this policy, even if the Commission finds a carrier to be "market dominant," a utility protesting a coal rate increase will have to prove that at least one of four so-called "constraints" has been breached. The problem with the constraints on rates is that they, like the Commission's "constraint" on ROI, form a lofty bridge over the waters of rail revenue. In fact, the National Association of Regulatory Utility Commissioners (NARUC) has called the ICC constraints "meaningless." If adopted, the ICC coal rate guidelines, NARUC said, "will sanction the unfettered exercise of rail monopoly power to the ultimate detriment of electric utility rate payers."[12] In fact, in promulgating the guidelines the Commission has advocated that the traffic having the least elastic demand (i.e., captive utility coal traffic) should be charged the highest rates and that the traffic having the most elastic demand (i.e., competitive traffic) be charged the lowest rates. This means that *because* an electric utility has no alternative but to pay whatever a railroad asks, the utility *should* pay that amount.

A brief examination of each of the four "constraints" on captive coal rates illustrates the reasons for NARUC's concern.

Stand-alone Costs. Under this criterion, the ICC would consider a rate rea-

sonable if it was less than what it would cost the shipper if it built and operated its own railroad. Despite the fact that the proposed coal rate guidelines have not been finally adopted, the ICC has already applied stand-alone costs in considering coal rate cases. In one case, Chessie estimated its maximum rates for coal could be increased under the "stand-alone" test from $13 per ton to $182 per ton—an increase of 1300 percent.

Obvious Management Inefficiencies. The so-called Long-Cannon provisions of the Staggers Act require the ICC to consider three factors in determining the reasonableness of rail rates for captive traffic: elimination of non-compensatory traffic, maximization of contribution from competitive traffic, and reasonable allocation of any resultant unavoidable revenue shortfall over the carrier's traffic mix.[13] In addition, the ICC is required to consider the impact of the rate on the attainment of national energy goals. The ICC has consistently resisted efforts to implement these requirements of the law. For example, whereas it is the railroads that possess the necessary data to carry out the intent of Long-Cannon, the ICC has cast the impossible burden on the shipper to obtain this data in individual rate proceedings. Moreover, even if the shipper manages to obtain data from a railroad to prove that it is "inefficient" in these ways, it must also prove that by eliminating such inefficiencies, a "revenue inadequate" railroad would become "revenue adequate."[14]

Phasing of Rate Increases. In its proposed policy, the ICC limited any increase in a single year to no more than 15 percent. This "constraint" would allow coal transportation rates to double within five years. Moreover, the 15 percent increase could be applied on top of increases allowed for inflation. This proposal flies in the face of Staggers language that contemplates overall annual increases of 4 percent above inflation for revenue inadequate carriers after 1984.

Revenue Adequacy. Until the ICC determines that a carrier is revenue adequate, it would be free to increase its rates unless it violates one of the three other constraints. As noted before, the Commission's revenue adequacy standards are so inflated that no carrier will likely exceed this constraint in the foreseeable future. Furthermore, the ICC proposes to allow revenue adequate carriers to continue charging higher coal rates until a shipper can prove that the carrier has "a consistent pattern of returns substantially in excess of its revenue needs."[15]

Individually and collectively, the Commission's proposed rate "constraints" offer no significant protection to utilities and electric rate payers.

Mark Borchelt

In the seasoned judgment of financial analysts and from most other indicators, the railroads are in relatively sound financial condition and are earning better than average profits from coal.

Regulatory Shell Games

Since the ICC seems determined *not* to find out for itself the railroads' true financial condition, regularly accepting the railroads' data as the basis for its calculations of revenue adequacy and pricing efficiency, the burden to do so falls on the shippers. This difficult

Mark Borchelt

Calculations based on railroad data indicate that coal revenues currently yield nearly twice the profit rate of other traffic.

task has been rendered virtually impossible by recent ICC rulings.[16] In effect, the ICC says a shipper has to prove its case before the railroad can be compelled to yield the data necessary to prove the case. And even when a state commission had found "inefficiency" in a captive coal rate case, the ICC refused to act to limit the increase.[17]

In another case, a group of utility coal shippers petitioned for a Long-Cannon ICC rulemaking to require the railroads to produce pertinent data. The Commission again refused to act, casting the burden of proof back on the shippers to obtain evidence in individual rate proceedings—a lengthy, uncertain, and costly procedure.[18]

Senator Russell Long, a co-sponsor of the Staggers Act amendment bearing his name, recently characterized the Commission's actions in regard to its implementation:

> . . . to put the burden on the utility to try to prove that a million customers are being victimized out there is contrary to the intent when the facts to prove it are in the possession of the other guy. And certainly if the Commission is not going to make him do it, they at least ought to see to it that those who are representing as many as a million consumers at a time have a right to look at those books . . . I do not think you (the ICC) have done it so far."

Chairman Reese H. Taylor of the ICC indicated he was sympathetic with implementation of the Long-Cannon criteria but acknowledged that, as yet, the ICC had not found a case of inefficiency and added:

> You can have all the laws in the world, and if you have a Commission that does not really want to implement them the way Congress intended, it is not going to make a bit of difference. That is really where we are with it. And I think that in due course, proper implementation will be afforded Long-Cannon. At least that is going to be my posture.[20]

At a minimum, this was a declaration of "non-feasance" on the part of the Commission and should serve as an indicator of the current bias of its majority.

Present Climate

In the present regulatory climate at the ICC, the electric utilities have been frustrated in their efforts to reverse or modify Commission rulings and proposed guidelines for future coal rate determinations. The Commission's responses routinely subordinate the concerns of the utility industry and consumers to the goal of assuring railroads they will be able to extract even greater profits from coal traffic.

Lacking data only the railroads can provide, one can assume that the 116 percent increase in coal rates from 1975 to 1981 will be easily surpassed in the future if the railroads continue to be found revenue inadequate. The railroads say that the rate of coal rate increases has slowed since October 1980 when the Staggers Act was passed. True. However, even prior to the issuance of coal rate guidelines, the growth of coal rates has outpaced that of other freight. Coal has been far from a laggard in railroad performance. As a recent Standard & Poor's report noted:

> The railroad industry is experiencing a renaissance fueled by rising coal traffic . . . Today, the fortunes of a number of railroads are inextricably bound to coal. . . . (Its) contribution to profits is even higher than to revenues, since substantial amounts of coal are transported via highly labor-efficient unit trains.[21]

In fact, calculations based on railroad data indicate that coal revenues currently yield nearly twice the profit rate of other traffic, on both a per ton and a ton-mile basis.[22]

The Implications

In the seasoned judgment of financial analysts and from most other indi-

cators, the railroads are in relatively sound financial condition and are already earning better than average profits from coal traffic. It is necessary, of course, for the Association of American Railroads and the ICC to paint a different picture if they are to succeed in exacting still more from U.S. electricity consumers. Because the production of all goods and services depends on electricity to some degree, consumers will be penalized for the ICC's largesse. In 1982, the utilities' coal rail bill was $5 billion. By 1992, it could approach $20 billion.

Consumers of electricity should not object to paying more for the transportation of coal to generate electricity if the price they absorb bears a reasonable relation to costs. However, if the railroads are in need of additional revenue beyond that needed to cover inflation, they should be subjected to the same scrutiny utilities face when asking for rate increases. First and foremost, this means providing evidence to support such increases and give affected parties a chance to challenge that evidence. Second, the various classes of customers should fairly share the burden of price increases. Third, the ICC should be required to enforce the Long-Cannon amendment. Left to its own devices, the ICC appears prepared to write the railroads a ticket good for unreasonable increases over a long period of time, with the U.S. consumers footing the bill. □

Notes

1. Wendell H. Ford, transcript, Oversight Hearing on the Staggers Rail Act of 1980, July 26, 1983, Sub-Committee on Surface Transportation, Committee on Commerce, Science and Transportation, U.S. Senate.
2. John C. Danforth, ibid.
3. Interstate Commerce Commission, order served August 24, 1983, (Ex Parte 450).
4. "Rail Performance Under Deregulation Keeps Wall Street Bulls Optimistic," *Traffic World*, September 12, 1983, p. 23.
5. Compiled from S&P Rail Index and S&P 500 Index 1976–1983.
6. General Accounting Office, report on Information on Regulatory Reform Under the Staggers Rail Act of 1980, August 17, 1983, p. 8.
7. "Accounting Changes Needed in the Railroad Industry" Report of the GAO, February 4, 1981, p. 21.
8. "Alternative ROI Computations, 1980, prepared by the Section of Financial Analysis," Corrected April 22, 1983. (Internal ICC document obtained under Freedom of Information Act.) For examples of acquisitions, see prepared testimony of Arthur J. Doyle, chairman of the board and president of Kansas City Power & Light Company, Oversight Hearing, op. cit.
9. With particular reference to captive coal shippers, the conference report supporting passage of the Staggers Act said:
   "The Conferees intend that this policy include the encouragement and promotion of the transportation of coal by rail in accordance with the objective of energy independence at rates which do not exceed a reasonable maximum where there is an absence of effective competition." (H.R. Report No. 96-1430, September 29, 1980, Title I, p. 80.)
10. Doyle, op. cit.
11. 49 U.S.C. Section 10709. For a fuller discussion of the market dominance test, see Joint Brief of Subscribing Petitioners and Intervenor Petitioners, November 10, 1981, before the United States Court of Appeals for the Fifth Circuit. Western Coal Traffic League *et al* v. United States of America and Interstate Commerce Commission (Docket No. 81-4257, *et al*).
12. National Association of Regulatory Utility Commissioners, comments on Coal Rate Guidelines, filed in ICC Ex Parte No. 347 (Sub-No. 1), July 28, 1983.
13. 49 U.S. Code Section 10707a (e) (2) (B) and (C).
14. See, for instance, Docket No. 38946, order served June 23, 1983, p. 10. Also see NARUC comments, op. cit., p. 9.
15. NARUC, op. cit., p. 10.
16. Doyle, op. cit.
17. NARUC, op. cit., p. 9.
18. Doyle, op. cit.
19. Oversight transcript, op. cit.
20. Ibid.
21. Klein, Stephen R., Standard & Poor's Industry Surveys, Railroads and Equipment, July 15, 1982.
22. See Table 1, Doyle, op. cit.

The Regulatory Process in Nuclear Programs

By Suzanne K. Phelps

Licensing uncertainties have a major impact on the costs and schedules of nuclear power plants.

In support of President Reagan's Private Sector Study reviewing the cost effectiveness of the federal government's regulatory actions, in August of 1982 the Edison Electric Institute (EEI) surveyed its members about regulation's impact on the costs and construction schedules of nuclear plants. Although it is impossible to single-out costs and delays caused by one regulatory change as opposed to those caused by other factors, the survey results suggest that the cost of regulatory changes for plants which received licenses since 1970 (or will soon receive licenses) amounts to billions of dollars. However, the results also show that while regulation has increased the amount of time and money required to build a nuclear plant, under the right conditions utilities can capitalize on their regulatory experience and thereby bring units on-line on reasonable schedules.

EEI collected information on two sets of nuclear units: Group I units, those licensed between 1970 and 1980, provide an historical perspective on construction costs and schedules along with a look at the costs associated with backfitting; Group II units, those licensed or expected to be licensed between January 1, 1980, and December 31, 1983, provide an August 1982 view of anticipated construction costs and schedules for bringing the plants on-line. Costs and schedules sharply contrast with the original estimates for these Group II units and with the historical data provided by the older plants.

Schedule Impacts

The survey asked utilities to report the time elapsed between receipt of a construction permit (CP) and receipt of an operating license (OL). These various times were compared to determine the magnitude of changes which have occurred between the two groups. (All times were normalized to a 1000 MWe plant, and, where more than one unit for a particular site received a CP on the same date, only the time for the first unit completed was compared.) The results indicate an average of 77 months from CP to OL per 1000 MWe unit in Group I and an average of 99 months per 1000 MWe unit in Group II.

Several pertinent factors must be considered when comparing the survey data to other statistics on nuclear plant lead times. First, as stated, these times were normalized to a 1000-MWe-unit reference base. Second, the results reflect only the time from CP to OL. Thus, utility planning time and the licensing application time required to obtain a CP, factors which were noted by some utilities to have had significant impact on schedules, are not included. Third, no account was taken for any construction work which might have been done prior to the issuance of a CP (e.g., during a period covered by a Limited Work Authorization).

Not surprisingly, the data from units receiving the first OL's after the accident at Three Mile Island's (TMI) Unit 2 clearly showed the effects of licensing delays as a result of that accident: 4 units licensed in 1980 and 1981 showed an average time between CP and OL of 121 months per 1000 MWe unit, and 14 units licensed or expected to be licensed in 1982 and 1983 showed an average time of 92 months per 1000 MWe unit. It should again be noted that this information is based on projections made in August of 1982; a number of schedules have changed since then.

Figure 1 shows the up and down trends in the length of time between the issuance of CPs and OLs. Several important points should be mentioned about these trends. First, the apparent

The original cost estimate for Duke Power Company's McGuire station, opposite, was $500 million. The total now is close to $2 billion.

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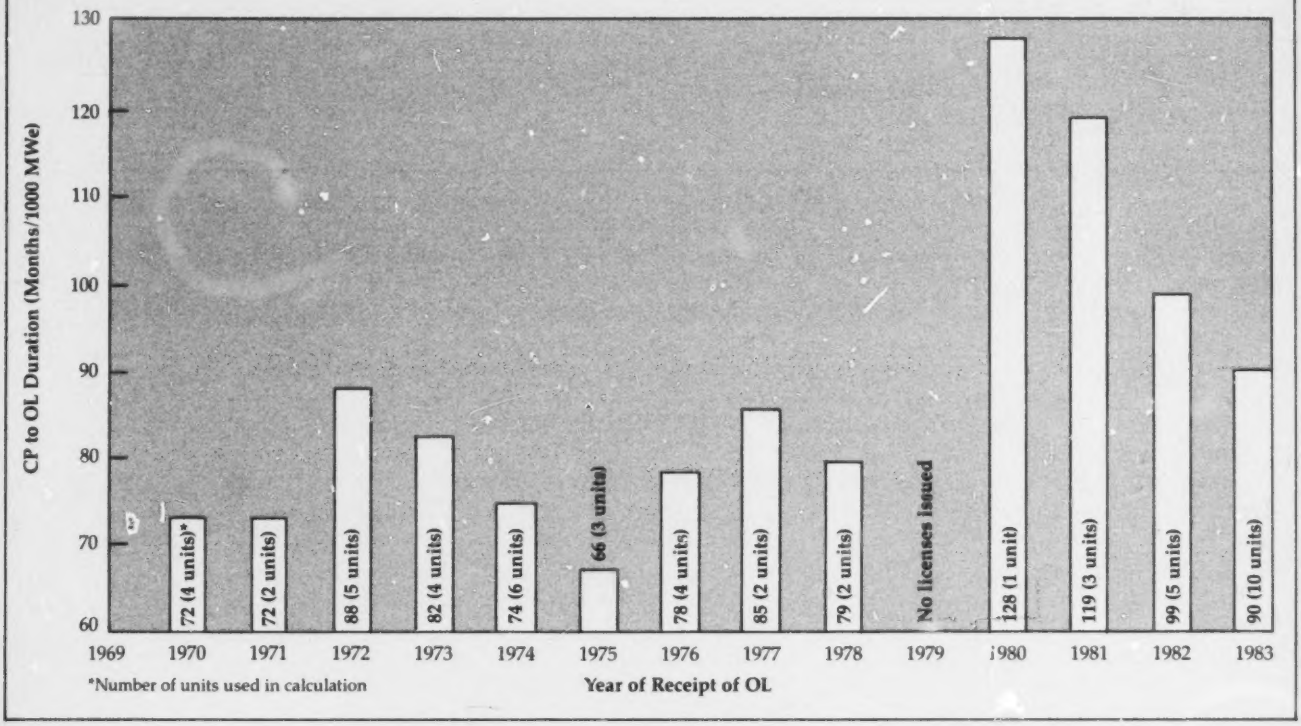
Figure 1.
CP To OL Duration Times by Year



downward trend in 1982 and 1983 is not entirely realistic, since many of the projections made in August 1982 have subsequently been extended. Second, the range of times in the years 1982 and 1983 are of interest. For 1982, the projected time between CP and OL projections for four units ranged from 74 months per 1000 MWe to 142 months per 1000 MWe. For 1983, the projections ranged from 65 months per 1000 MWe to 157 months per 1000 MWe.

Cost Impacts

For the Group I plants, EEI requested that the utility provide the actual capital cost of the plant at the time the OL was received. Results are shown as "Initial Capital Costs" and as "Costs—$/kw" in *Table 1*. This table lists the units in decreasing order according to length of time since receipt of the OL. For the Group II units, EEI requested the estimated cost at the time the CP was received, plus the actual or most current (August 1982) cost estimate at the time the OL was or will be received. This data is presented in *Table 2*, and is indicated by the "Capital Cost Estimate" and "Cost—$/kw" columns under both the "Estimate at CP" and "August 1982 Estimate" headings. The Table 2 units are listed in decreasing order by length of time since issuance of the CP. In both tables, some of the individual numbers provided by utilities were qualified as rough estimates. Also, some utilities reported only overall plant costs for multi-unit plants. For listing and calculation purposes, in those instances costs were divided equally among the multiple units. In spite of these inconsistencies, the trends and the magnitude of the numbers involved are clear.

For plants licensed in the 1970–1972 period, capital costs averaged approximately $188 per kw. By the 1976–1978 period, the average cost of the surveyed units had risen to approximately $615 per kw. If one assumes an annual inflation/escalation factor of 9 percent each year during the 1970s, the 1976–1978 costs should have been about $314 per kw—only 51 percent of the actual average cost reported on the surveyed

Table 1.
Capital and Backfit Costs for Nuclear Power Plant Units Receiving Operating Licenses Between 1-1-70 and 12-31-78

Plant ID	Initial Capital Cost (Million)	Cost $/kw	Retrofit Costs* NRC Backfit Costs (Million)	NRC-TMI Backfit Costs (Million)	Utility Backfit Costs (Million)	Total Backfit Costs (Million)	Capital Costs to Date Initial and Backfit (Mil)	Projected Additional Backfit Costs (Mil)
101	67	96	23	5	32	60	127	27
102	118	217	47	26	10	83	201	111
103	75	151	NA	12	NA	28	103	NA
104	101	153	108	6	22	135	236	NA
105	103	130	35	6	22	63	166	24
106	83	167	NA	12	NA	28	111	NA
107	250	317	69	30	NA	99	348	12
108	107	154	17	9	114	141	248	30
109	181	352	28	3	3	34	215	NA
110	150	190	48	8	17	73	223	36
111	112	142	48	8	17	73	185	36
112	146	186	69	30	NA	99	245	12
113	208	238	80	40	45	165	373	85
114	164	185	47	7	5	60	224	40
115	273	263	21	13	9	42	315	8
116	98	142	17	9	114	141	240	30
117	206	389	20	12	11	43	250	58
118	164	185	47	7	5	60	224	40
119	284	273	21	13	9	42	325	8
120	264	491	73	NA	4	77	341	109
121	262	308	17	20	24	61	323	13
122	315	296	58	5	19	81	396	39
123	164	185	47	7	5	60	224	40
124	387	498	44	7	18	69	456	16
125	480	456	14	10	40	64	544	7
126	206	389	20	12	11	43	250	58
127	315	296	58	5	19	81	396	39
128	336	409	43	5	58	106	442	52
129	436	516	23	17	17	57	493	20
130	424	487	42	5	46	93	517	NA
131	452	400	29	24	52	106	558	35
132	480	598	42	16	61	118	598	36
133	669	807	14	1	11	26	695	10
134	296	361	28	4	47	79	375	32
135	626	574	23	14	NA	37	663	9
136	318	376	11	7	8	26	343	9
137	583	643	80	35	39	154	737	32
138	784	864	35	15	NA	50	834	6
139	521	474	14	10	40	64	586	7
140	508	649	44	7	18	69	577	16
141	651	714	1	15	6	22	673	12
Total	12,367	—	1,505	502	988	3,012	15,380	1,154

*Dollars shown are listed as received from the utility. No attempt was made to convert to 1982 dollars.
NA—Not available.

Table 2.
Licensing Costs and Schedules for Nuclear Power Plant Units Receiving Operating Licenses Between 1-1-80 and 1-1-84*

	Estimate at CP			August 1982 Estimate				
Plant #	Construction Duration CP to OL (Months)	Capital Cost Estimate (Million $)	Cost $/kw	Construction Duration CP to OL (Months)	Capital Cost Estimate (Millions $)	Cost $/kw	Months Change	Cost Change (Mil $)
201	56	159	143	152	666	597	96	507
202	49	184	203	114	532	587	65	348
203	49	145	175	103	838	1,011	54	693
204	36	452	391	129	2,350	2,036	93	1,898
205	68	383	449	132	1,695	1,989	64	1,313
206	80	383	449	127	1,695	1,989	47	1,313
207	37	247	209	106	978	828	69	731
208	49	247	209	122	978	828	73	731
209	48	350	412	116	2,600	3,062	68	2,250
210	59	439	382	103	1,368	1,193	44	930
211	64	358	313	115	1,040	907	51	681
212	66	693	601	104	1,925	1,671	38	1,233
213	60	879	675	93	2,386	1,833	33	1,507
214	42	445	400	98	1,808	1,624	56	1,363
215	54	390	339	96	1,720	1,496	42	1,331
216	53	674	573	92	1,658	1,411	39	984
217	66	923	746	87	1,565	1,264	21	641
218	61	1,007	839	88	1,760	1,467	27	753
219	49	1,011	839	78	1,983	1,645	29	971
220	65	850	1,000	68	1,420	1,671	3	570
221	65	1,041	906	79	1,927	1,676	14	886
Totals	—	11,260	—	—	32,892	—	—	21,634

*Projected costs and schedule estimates based on survey conducted by EEI in August 1982.
All costs rounded.

units. (The 9 percent inflation/escalation factor is obtained by using the average GNP deflator factor of 6.8 percent for that period and increasing it by one-third to recognize a higher value for construction escalation.)

Data available on the 21 units in Group II, which have a combined capacity of 22,360 MWe, reveal an anticipated completion cost in the range of $587 to $3,062 per kw. The total cost of these 21 units by the time all OLs are received (as anticipated in August 1982) should reach almost $32.9 billion, nearly triple the amount—$11.3 billion—estimated when the CPs were received. Cost changes are listed in the last column of Table 2. If the 1970–1972 average construction costs had risen only by the 9 percent annual inflation/escalation factor from 1972–1979 and by a larger 12 percent factor between 1979 and 1983, the total cost of the 21 units would have approximated $12 billion—a figure very close to the estimate utilities made when the CPs were received.

Backfitting Costs

Utilities with Group I plants were asked to provide estimates of the costs of backfitting that occurred after the OLs were issued. The backfitting costs were broken into three categories: those initiated by the utility, those initiated by the Nuclear Regulatory Commission (NRC) as a result of the TMI accident, and other NRC-imposed backfits. For the 41 units shown in Table I, utility-initiated backfits totaled almost $1 billion, NRC-TMI backfit costs totaled $.5 billion, and other NRC-imposed backfit costs totaled $1.5 billion.

The fact that one-third of the $3 billion total was attributed to utility-initiated backfits demonstrates that

utilities are not opposed to making plant improvements when new information warrants them. Their concern arises because two-thirds of the backfit costs resulted from NRC-initiated requirements for which no quantifiable cost-benefit analyses are available.

The utilities also were asked to provide estimates of projected additional backfit costs for the next several years. These costs, attributed to known or anticipated NRC requirements, amount to an additional $1.2 billion. (As with capital costs, it should be noted that when utilities provided only overall plant backfitting costs for a multi-unit site, the costs were listed as if equally divided among the multiple units.)

On June 14, 1983, in testimony on licensing reform before the Senate Environment and Public Works Committee's Subcommittee on Nuclear Regulation, William S. Lee, Chairman of Duke Power Company, offered the following remarks:

> The NRC has made attempts in the past to estimate the costs for specific backfits. However, those costs are sometimes not accurate. For example, Northeast Utilities selected certain requirements from NRC's TMI Action Plan (NUREG-0660) and compared the NRC's cost estimates to the actual capital costs for implementing those requirements at its Haddam Neck Plant. The installation of Reactor Vessel Head Vents was estimated by the NRC to cost $100,000; in actuality it cost $1,102,000. System Integrity Review was estimated to cost $5,000 per plant by NRC; in actuality it cost $1,144,000. By contrast, the NRC estimated that Plant Shielding Review would cost $50,000; instead it cost $6,000. Northeast Utilities concluded: "(H)ad the NRC performed realistic Value-Impact Analysis on recent TMI Action Plan requirements and properly weighed cost against benefit, a number of requirements would not be justified in terms of increased plant safety." These examples do not instill confidence that all of the billions of dollars spent on backfitting to improve safety have been spent to the best advantage.

The NRC changes, which are intended to improve the protection of public health and safety, have evolved as knowledge about nuclear plants has steadily increased. The regulators desire to respond to real or perceived problems, however, has not been balanced adequately by objective reviews of the costs in light of the benefits of risk-reduction or improved safety effected by the individual changes. Because NRC has not established a systematic, centralized method for such evaluation, it is impossible to determine if cost increases, which are ultimately borne by the utility rate-payer, have been spent to the best advantage, or, in some instances, whether they have been spent to improve safety at all.

Florida Power & Light Company's St. Lucie project—Units 1 and 2, above. Unit 2 was completed only two months off the original schedule.

Case Studies

In an effort to compare costs and schedules of units which were as similar as possible, two large, experienced nuclear utilities, Commonwealth Edison Company and Duke Power Company, were asked to provide specific comparisons of some of their earlier units with their units which are now coming on line.

Commonwealth Edison compared its Zion and Byron power stations. Each station has two pressurized water reactors (PWRs) of approximately the same size, originating from the same manufacturer, designed by the same architect-engineer, and built by the same contractor. The actual cost of the Zion station was almost $600 million. It began commercial service in October 1973 after a 52-month construction period. Commonwealth estimated the cost for the Byron station to be nearly $2.8 billion and expected it to enter commercial service in February 1984 after a 92-month construction period. When the Zion costs were escalated to correspond with the Byron cost estimate, the result was a comparative Zion cost of a little less than $1 billion.

The Road To Licensing Reform

There is perhaps one point on which the nuclear industry, its regulators, and its detractors are in total agreement: due to their unstable state, licensing procedures for nuclear power plants currently work to no one's best interest. From mid-1974 to the present, the time involved from planning a nuclear power plant to its actual operation increased by about 70 percent. A major contributor to this increase—and to consequent increased costs—has been the instability of the NRC's regulatory requirements. The unpredictability created by this instability makes it difficult to know when capacity will be available to meet demand, and thus rational planning is difficult. Continual regulatory changes typically result in a plant being significantly different at the time of its operation than envisioned when construction began. This constant state of change also hinders the job of safety assessment for both the industry and the regulators. The current protracted two-stage hearing process—one for a construction permit and another for an operating license—gives public participants the opportunity to challenge major issues only at the second stage. By then a billion dollar plant already sits in place waiting for a lengthy hearing to conclude before it can run.

In response to this problem, the NRC and the Department of Energy both have developed licensing reform bills. Formally introduced as legislation earlier this year, the bills address the problem with different approaches, but in tandem they provide an appropriate base for achieving a viable solution.

Last June, in testimony on the bills, Duke Power Company Chairman William S. Lee outlined the criteria for legislation that would correct the known problems of the current process:

1. A requirement that the NRC analyze any new or modified regulatory requirement to determine if the requirement is justified in terms of its overall plant safety and the resources necessary to implement it.
2. Replacement of the current time-consuming adjudicatory hearing structure with a less formal hybrid hearing style.
3. A provision for issuance of a combined construction permit and operating license in a one-step licensing proceeding for future applications.
4. Authorization for approval of standard plant designs and directions to the NRC to establish procedures to encourage standardization.
5. A provision for pre-approval of plant sites, separate from a facility application.
6. Provision for early public participation in the decision-making process.

The proposed reform is in no way intended to hamper or negate the NRC's authority to require analysis, engineering, and hardware changes where protection of the public health and safety warrants such action. However, the imposition of billions of dollars worth of changes—ultimately paid by the same public whose safety is being protected—certainly calls for a systematic and analytic consideration of safety benefits and costs. For this reason, reform is essential to ensure reasonable stability and control to the planning, building, and operation of nuclear power plants. Without it, Lee concluded, the NRC licensing process ". . . will bar the continued use of nuclear power in this nation." □

The difference between the escalated Zion cost and the estimated Byron cost was thus about $1.8 billion. While some of the cost and schedule increases were attributed to company-initiated improvements in operability, maintainability, and reliability, the largest percentage of this increase is considered to be due to NRC regulatory action.

Duke Power Company provided a comparison of the costs of its Oconee, McGuire, and Catawba stations. All of these stations have PWRs, and all three were designed and constructed by the Duke Power Company. The McGuire station consists of two PWR units with a combined capacity of 2,360 MWe. Construction permits were issued by the NRC for these units in February 1973. When the CPs were received, the cost for the two units was estimated to be about $500 million, and commercial operation dates of March 1976 and March 1977 were anticipated. The current cost estimate for the two units was given as $1.9 billion or the equivalent of $828 per kw. Commercial operation was set at December 1981 for the first unit and October 1983 for the second unit. A 1982 equivalent-cost for the McGuire station was determined by escalating the dollars spent each year during construction to 1982 dollars. This calculation provided a total cost of over $2.9 billion—or the equivalent of $1,247 per kw.

The Catawba station consists of two PWR units with a combined capacity of 2,290 MWe. Construction permits were issued by the NRC for these units in August 1975. When the CPs were received, the cost for the two units was estimated at a little more than $1 billion. Commercial operation dates of January 1981 and January 1982 were expected. The August 1982 cost estimate for the two Catawba units was almost $3 billion, which is equal to $1,279 per kw. These figures are based on commercial operation dates of March 1984 and September 1985. A 1982 equivalent-value for the Catawba units, determined by escalating funds spent before 1982 to 1982 dollars, is over $3.3 billion, which is equal to $1,469 per kw.

The costs of the three PWR units at Oconee were used as a benchmark for comparing the impact of regulation on

the later units. Prior to 1974, practically all of the materials for Oconee had been purchased and most of the labor performed. Thus, the actual Oconee cost of $185 per kw was taken as a conservative representation of the cost in 1973 dollars. By using the inflation factors of the Bureau of Labor Statistics of Atlanta, Georgia, and by adjusting the number to account for three units at the station, the 1982 equivalent-cost of the Oconee plant was calculated to be about $445 per kw for a two-unit plant —assuming the regulatory environment remained constant between 1973 and 1982. However, excluding inflation, the primary difference between 1973 and 1982 *was* the regulatory environment. Therefore, a majority of the additional costs for McGuire and Catawba may be attributed to regulatory changes. While a portion of the added costs for McGuire and Catawba—as with Byron—is the result of changes desired by the utility, it was conservatively estimated that at least 60 percent of the increase was the result of NRC-imposed regulatory changes. The additional cost in 1982 dollars was estimated to be nearly $1.9 billion for the McGuire station and about $2.4 billion for the Catawba station.

The St. Lucie Example

The survey results confirm that the changing regulatory environment has had a major impact on nuclear plant schedules and costs. However, they also contain data that indicates that the construction of nuclear power plants can be a manageable technology.

Florida Power & Light Company's St. Lucie Unit 2 is a good example. From the receipt of the CP to the receipt of the OL took only six years. Commercial operation was achieved only two months off the originally scheduled plan. Others who have examined St. Lucie 2 in depth have noted some of the factors that contributed to the timely completion of the unit. For example, a report in the April 21, 1983, issue of *Engineering News-Record* cited the following factors: St. Lucie 2 is a near twin of St. Lucie 1; the design of Unit 2 was nearly 75 percent complete before construction started; Florida Power & Light encountered little public opposition to its application; and Florida Power & Light took a very aggressive management stance on the project. It is also significant that each of the St. Lucie units had a separate CP application, unlike the more usual case for a two-unit plant in which a single CP application is filed for both units, or both CPs are issued on the same date. The Unit 1 CP application was filed in January 1969, and the CP was issued in July 1970. The Unit 2 CP application was filed in April 1973, and the CP was issued in May 1977. Because construction on Unit 2 began just as Unit 1 was nearing completion, many of the laborers who worked on the first unit were available for the second unit. Close to 80 percent of the skilled laborers and half of the nonmanual staff stayed on to build the second unit.

Regulatory changes cost nearly $1.5 billion at Duke Power Company's Catawba station, above.

* * *

The survey results suggest that under the right conditions the process can be made to work. At the same time, however, and in spite of the admitted imperfections and shortcomings of the data collected, the survey results clearly illustrate that the changing regulatory environment has had a tremendous impact on nuclear plant costs and schedules. The existing, drawn-out licensing process has resulted in dramatic increases in time and cost. The utility industry's call for rational control—not elimination—of backfitting requirements is plainly justified when one considers their multi-billion dollar impacts. It is the responsibility of the industry and its regulators to provide the basic reform and commitment needed to help preserve the viability of nuclear power. □

Richard J. Arnold, a freelance writer living in Washington, D.C., also contributed to this article.

Counterclockwise from bottom, PEPCO employees Karen Kappis, Patrice Kelly, and Mary Cochran.

BEST AVAILABLE COPY

Women in the Electric Utility Industry

By Mark R. Reynolds

Typifying a nationwide trend, women at Potomac Electric Power Company increasingly are taking jobs traditionally held only by men.

Sarah West recalls a morning years ago when she sat at her desk and waited for a telephone company repairman to show up and restore service to her office at Potomac Electric Power Company (PEPCO). When the phone company's repairman arrived, in spite of traditional signs of the trade like a jingling toolbelt strapped at the waist, he wasn't a repairman at all. This repair*man* was a repair*woman*.

West recently reminisced about changes that have occurred since that early experience with a woman in a nontraditional job. Today, as manager of corporate staffing at PEPCO, she has been involved in sweeping social changes that have redefined "a woman's place" and redirected assumptions about roles and career alternatives for women in our society. PEPCO's Women in Nontraditional Jobs program in fact recently received an Edison Electric Institute Meritorious Achievement Award for its strides in incorporating women into its total work force.

"It was commonly believed that only men had the ability to do certain jobs," West says. "But women *can* do these jobs too." Today women are proving the truth of West's statement throughout the electric utility industry. At PEPCO and at other utilities across the country, women are increasingly taking on jobs traditionally held only by men. Not only are women executives and corporate managers, but they are also electrical engineers, mechanics, and even line*persons*.

"I don't think that I could sit behind a desk all day," Karen Kappis maintains, and as a PEPCO laboratory technician she is seldom sitting at all. Instead, dressed in jeans, heavy work shoes, and a hard hat, Kappis is out climbing around cooling towers and generating plants collecting water samples used in environmental studies as well as samples for other analyses. She is happier and more satisfied doing the kind of work in which "you occasionally get dirty." Hers is not "a high-heeled job," and she likes it that way.

Before coming to PEPCO, Kappis had "never even envisioned" the operations of an electric utility, let alone the possibility of a career in the industry. "When I thought about electricity, it was only as something you got when you flipped the wall switch," she laughs. Thanks to affirmative action programs like the one at PEPCO, however, women now have increased understanding of the operations of the electric utility industry, and such awareness fosters career access.

Over the past few years, Sarah West has seen a "great change" with regard to women in the electric utility industry. The key to this change, she feels, is education. Women are being educated about the kinds of jobs that are available, and educated to perform in those jobs. "More and more women are coming into our office and asking for blue-collar and other nontraditional jobs," West adds. "It wasn't like that a few years back."

Women are seeking nontraditional jobs more and more because they are increasingly aware that such jobs exist and that they can do them. At job fairs and on college campuses throughout the metropolitan Washington area, PEPCO representatives encourage young women to investigate careers in the electric utility industry, outside of the areas in which women have traditionally sought employment. In the personnel offices at PEPCO, the staff makes sure it discusses blue-collar positions with all female applicants, even those who come in seeking clerical or

Mark Reynolds is a freelance writer living in Washington, D.C.

Karen Atkins

Karen Atkins was always pushed by her parents to be independent, to follow her own interests even if they led in unusual directions. She is not the first in her family to hold a nontraditional job; her father was a nurse in a Veterans Administration hospital. Success, for Atkins, depends on "the goals and standards I've set for myself and on how I deal with my colleagues." What Atkins wants most of all in her career is "the respect and cooperation of the people I work with."

Clearly, Atkins has earned that respect and enjoyed a great deal of cooperation. In eleven years at PEPCO, she has steadily worked her way up from an entry-level position as generating assistant to her current position as chief chemist for production. "The company has been very supportive," Atkins says, "and the production group with which I work has been a springboard for expressing my creative talent and for learning from my not-so-good ideas."

Atkins' only problem right now is explaining to her son why men are always calling her at night. "It's part of the job as a chemist," she quips. Her husband? "He got used to it a long time ago." □

Patrice Kelly

Patrice Kelly, a special police officer at PEPCO, laughs at the kinds of questions her mother and sisters always ask about her job. "They're always after me with 'Aren't you afraid to carry a gun?' and 'Don't the guys hassle you?'" she relates. However, it was a woman, not a man, who originally inspired Kelly's interest in pursuing her nontraditional career. A girlfriend's mother was working as a ser-

geant on a security force, and Kelly would sometimes visit her on the job. She found the work exciting and challenging.

Kelly admits that the first time she fired a gun, she "went all to pieces," but since then she has not encountered any trouble that she couldn't handle. Kelly trained at the Washington Gun Service, and her preparation covered not only the use of firearms, but a variety of other topics, such as Constitutional law, CPR, and self-defense. Though she was the first female security officer at PEPCO, Kelly does not see herself as out of the ordinary. "I'm from the generation of women who have been doing this kind of thing for years," she says. "It's not unusual to me."

As for sexism on the job, Kelly's only problem with the male officers was that, at first, they "spoiled" her. "They'd bring me cakes, pies, cookies; I put on a lot of weight." □

Karen Kappis

Karen Kappis had little educational background to prepare her for the laboratory technician position she now holds at PEPCO. Born and raised in Germany, she took a couple of chemistry courses at night school after she came to the states, and she did some electronics work in New York. Essentially, however, she "fell into this job. Then I found out that I loved it."

A newspaper advertisement led Kappis to PEPCO. Initially, she was attracted by the ad's mention of lab work. "The power plant aspects I will learn in time," she told herself. Yet, when the quiet laboratory she expected didn't materialize, learning about the power plant itself became her first priority. "For the first few weeks I was scared to death," Kappis admits. "The ground shakes from the action of the big boilers. There's quite a bit of noise; you have to wear earplugs. Hard hats are required—and necessary. This is definitely a new place for women."

Fear quickly gave way to excitement when Kappis realized that she was beginning to understand what is required to generate the electricity she had always taken for granted. "Few people, especially women, realize how much there is to this industry," Kappis says. "It's fascinating work. There's so much to learn, and where I'm working, I can see exactly where everything comes from."

Though power plants are relatively new places for women, Kappis does not consider herself a pioneer, perhaps because half of the lab technicians in her area are female. The men she works with have always been "nice and helpful." There is no sexism on her job, Kappis maintains. □

Above, PEPCO relay tester Rosemary Hinley, and below, PEPCO manager for funds management Mary Cochran. At Columbia University where Cochran took her MBA, only four percent of the students in the program were female.

secretarial work. In these and other ways, PEPCO strives to make women aware that such jobs do exist, and that women can (and *do*) get them.

Even for women with educational backgrounds in mathematics or science (traditionally "male" fields), jobs in the electric utility industry were not generally perceived as career alternatives. Karen Atkins remembers a particular chemistry teacher ("male, of course") at Howard University who sparked her interest in science. He said that "science was the road of the future for women as well as men," Atkins recalls. When it came to thinking about the future, however, a career in medicine or teaching seemed the only logical alternatives for a woman with her scientific background. Atkins was working in a lab at Washington's D.C. General Hospital when, on the spur of the moment, she stopped in at PEPCO and filled out an application. "I was looking for something different," Atkins says, although at the time she had little knowledge of what sort of job she might do for the electric company. "I didn't even know that PEPCO had a lab," she admits. Eleven years later, Atkins has added to her scientific expertise a working knowledge of the mechanical and engineering aspects of electrical generation, and she has moved up at PEPCO from generating assistant to chief chemist for production.

At Howard University Atkins was used to being "just one of the guys" since most of her science classmates were male. Similarly, Mary Cochran was one of the only women at her undergraduate college who went in for mathematics and computer programming, and at Columbia University where she took her graduate degree, only 4 percent of the students in the MBA program were female. As chartered financial analyst, Cochran worked for five years in a trust department, then for two years for the Federal Reserve Board before joining PEPCO. She was increasingly bored by the kind of work she was doing, and equally uninterested by the kind of work she saw ahead in banking, which seemed at the time the next logical career step. When the position at PEPCO appeared, "it seemed an attractive alternative."

As PEPCO's manager for funds management, Cochran is involved in a wide variety of financial activities, such as mobilizing and investing company funds, cash forecasting, benefits financing, and short-term investment analysis. She feels she has learned a "tremendous amount" facing the daily challenges in her busy office during her six years with the company. Comparing her present job with her previous position supervising holding companies for the Fed, Cochran finds that she is "much happier *doing*" than she was "keeping others from *doing*."

A Little Help Along the Way

Both PEPCO employees Mary Cochran and Karen Atkins were among the first of a growing number of women whose early career planning decisions prepared them for jobs in traditionally male fields. Such options have not always been available for women, and still are not available to everyone equally. Historically, females—particularly from lower income and minority groups—have been deprived of the education and work experience necessary to compete in the job market. As a result, these women must seek new training in occupational skills and must learn to adopt new images of themselves as competent and secure in jobs that they probably never considered. Wider Opportunities for Women (WOW), an independent, non-profit Washington, D.C., organization, provides just this kind of training.

For almost 20 years, WOW has worked to achieve equal employment opportunities for women through equal access to and training for jobs. At WOW women on welfare or with minimal job skills can enroll for 20-week courses in areas such as electromechanics, and WOW's placement service provides personal assistance in securing positions for its graduates. PEPCO is one of a number of companies in the Washington area that recruit women from WOW's program. PEPCO recognizes that women and electric utilities are *both* better served when the greatest possible number of people (male and female) are capable and productive; it makes for a stronger industry and a better society.

When Rosemary Hinley was in high school, all she wanted "was to get out." Before coming to work for PEPCO, she had held an assortment of jobs (elevator operator, motel clerk, security guard), and she knew that she was not interested in a clerical position that would confine her to a desk. ("How do secretaries stand dressing-up everyday?" she ponders.) Hinley gave little thought to returning to school. Now, however, she is enrolled in Prince George's Community College, pursuing a degree in mechanical technology. Hinley's work as a relay tester for PEPCO had a lot to do with her decision to return to school. She found the work "interesting and demanding," and she began her new course of study in order to meet those demands and to acquire the skills necessary for career advancement. PEPCO's Tuition Aid Program is making Hinley's education possible.

Begun in 1976, the Tuition Aid Program (also cited in EEI's Meritorious Achievement Award to PEPCO) encourages all employees to continue their formal education. The program provides prepayment of a substantial portion of the cost of enrolling in an approved school, college, or university for the purpose of improving job performance and preparing for promotional opportunities within the company. The program has also aided the company by making recruitment more competitive and by strengthening its "promote from within" policy. □

The "problem" for women in society and in the work force has long been that historical attitudes and deep-seated social assumptions kept them locked into stereotypical roles and traditional careers. Fortunately, such attitudes and assumptions are changing. Affirmative action programs like those at PEPCO serve both men and women by ensuring that sexually-defined restrictions on the expression of one's talent or capability do not exist. If women are deserting their historic domestic posts to go out and work, men who desire it are earning a greater freedom to stay home and raise the family. PEPCO's staffing reflects the change in both directions; recently, a male secretary was hired to work for a female manager. "Affirmative action" Sarah West remarks, "is good for *both* sides." □

Capital Formation, Productivity, and the Impact of Government Regulation

By Douglas C. Bauer and Bruce G. Humphrey

Government policies directly affecting capital formation indirectly affect the nation's productivity growth.

In an attempt to develop a national consensus on future economic growth and in response to a Congressional resolution, President Reagan initiated a series of regional conferences on productivity in 1983. These conferences—on capital formation, human resources, government involvement, and private sector initiatives—culminated in a White House conference on productivity.

As a participant at the regional conference on capital formation in June, Edison Electric Institute (EEI) Senior Vice President for Economics and Finance Douglas Bauer had stressed that investor-owned electric utilities need large amounts of capital if they are to meet future demand. He also emphasized the need for economic consistency stating, "You can't change the rules every two years."

The Administration then requested Dr. Bauer to present follow-up information on the electric utilities' perspective on capital formation, productivity, and the impact of government at the September White House conference.

In response, Dr. Bauer and Dr. Bruce Humphrey, EEI Director of Energy Modeling and Economic Research, developed the following commentary.

Capital formation and productivity remain problems for both corporate planners and government policymakers. The relationships between the two are difficult to conceptualize and even more difficult to quantify. Net fixed investment as a percent of net output was about the same in 1961–65, a period of high productivity growth, as it was in 1976–80, a period when slowed productivity growth became unmistakably apparent.[1] Nevertheless, it is likely that the slowdown in productivity growth since 1965 has been caused in large part by an insufficiency in productive investment. In fact, a survey of recent studies indicates that 20 to 40 percent of the decline can be attributed to inadequate capital formation.[2]

The linkages between capital formation and productivity growth are especially important to the electric utility industry for several reasons. First, the industry is highly capital intensive. Not only is electricity produced by a capital intensive process, but also, except for government, utilities are the dominant participants in capital markets, accounting for one-fifth of all new industrial construction, one-fourth of all corporate financing, and one-half of all new common stock issued for nonfinancial companies. During the 1983–1987 period, electric utilities expect to spend $160 billion on construction of new plant and equipment alone.[3] Second, economic incentives in place today make the industry highly capital averse. Since 1973, the industry's earned rate of return has failed to reach the rate of return allowed by regulatory commissions. Thus, the industry has been under-recovering investment costs for the past ten years. This condition, combined with rising costs and uncertain future demand, biases incentives toward under-investment.[4] Third, the productivity of public utilities has declined along with that of the economy as a whole. Four-fifths of U.S. industries have experienced lower productivity growth since 1973 than they had from 1948 through 1972. The average annual rate of change declined from 3.0 percent to 0.8 percent from 1973 to 1981; for electric utilities during this period, productivity growth declined from 6.4 percent to 0.9 percent.[5] Thus, how capital formation and productivity growth are linked and what

actions the government takes affecting investment and productivity will affect the operational decisions and the economic performance of the industry.

In addition to the industry being capital intensive, the capital itself has characteristic attributes. First, investment in plant and equipment has an exceptionally long lead time. Nuclear plants, which are relatively capital intensive, require approximately twelve years to build, and coal plants, relatively fuel intensive, require seven years. Second, once a plant is in place it will remain in place a long time. The median years of service life for plants that have retired is 40 to 50 years with nearly 10 percent of retired plants exceeding 55 years of service life.[6] Third, the existing capital stock is aging. In 1970, 47.8 percent of the industry's capacity was ten years old or less. By 1980 this percentage had fallen to 41.6, and by 1990 it is expected to fall to 25.5.[7]

Although electric utilities are more capital intensive than most industries, adequate and appropriate capital and equipment is central to the productivity performance of the economy as a whole, as well.

Although electric utilities are more capital intensive than most industries, adequate and appropriate capital equipment is central to the productivity performance of the economy as a whole, as well. And, just as with utilities, capital in other sectors is long-lived. Fifty-seven percent of the existing stock of plant and equipment is greater than 25 years old.[8] Thus, productivity performance today and in the future is greatly dependent upon the capital now in place.

Capital in place today was chosen in light of the economic incentives, technology options, institutional arrangements, and regulatory requirements at the time of the investment decision. Given the age of existing plant and equipment, it is obvious that conditions are now far different than they were when many of the decisions were made. Also, conditions have changed much more rapidly than could have been anticipated. Energy prices have risen dramatically. The technology of production, especially "high-tech" production, has fundamentally changed. Also, the preponderance of the nation's productive capital was put in place in an era prior to the existing pattern of health, safety, and environmental regulations. Consequently, a significant portion of our plant and equipment probably is economically obsolete. Both its quantity and its quality are likely to be inappropriate for today's conditions.

Because of this accelerated economic obsolescence, the value of capital computed using traditional economic and accounting techniques is probably not indicative of its current economic worth. Furthermore, this induced but unmeasured loss in the value of capital has probably been a factor in the poor productivity performance in recent years.

Traditional calculations of total factor productivity, designed to measure the productivity with which all the inputs of production are combined, do not consider the vintage or quality of the capital stock. If accelerated economic obsolescence has occurred, as seems likely, then traditional calculations over-value capital inputs and understate productivity growth. Thus, the slowdown in productivity growth can perhaps be partially explained by the fact that a portion of the capital stock has outlived the conditions for which it is appropriate. During a time when conditions change dramatically, this phenomenon must become more important.

While the existence and consequences of this phenomenon have been suspected for some time, only recently have the analytical barriers for measuring its extent been surmounted. A study by Ernst Berndt and David Wood of MIT has found that the oil price shock of 1973–74 made 8 to 22 percent of the existing capital stock economically obsolete by 1977. That is, the traditional capital stock accounting measurement procedures overstated the capital stock in U.S. manufacturing. Or, more dramatically, the 1973–74 oil price shock destroyed 8 to 22 percent of the economic value of the capital stock.[9]

What do these linkages between capital formation and productivity growth imply about the impact of government actions on productivity? To the extent that unanticipated government decisions change the parameters of investment decisions, they render capital in

place economically obsolete, thereby increasing the investment required to replace capital above what would otherwise be normal. In effect, therefore, instability in government policy decreases the value of existing capital to the private sector and depresses productivity growth.

The electric utility industry, which has shared in the productivity growth decline, has been through a decade of events that have radically altered the risks and costs of capital investment. Many of these changes have resulted from government decisions. An obvious example is the much needed environmental regulation. Our nation's environmental goals are critical to our quality of life and we must vigorously strive to achieve them. But, we must note that pursuit of these goals imposes costs and requires trade-offs with other national goals such as productivity growth. In 1982 the electric utility industry spent $2.9 billion on pollution control.[10] The capital in place ten years ago was simply not appropriate for the new national priorities. Modifying the capital stock by retrofitting existing equipment and adding new plant and equipment resulted in significantly higher generating costs and reduced productivity growth. A recent study has shown that annual average productivity growth in the electric utility industry from 1973 to 1979 would have been 44 percent higher had it not been for sulfur dioxide regulations.[11]

Now that these costs have been incurred and substantial environmental benefits have been gained, the electric utility industry may be approaching another round of expensive retrofitting and other changes in response to the acid rain debate. Regardless of the benefits and costs of additional controls, the uncertainty that the debate creates and the possibility that costs will be imposed are already affecting investment decisions and placing in doubt the economic value of the plant and equipment now in place.

Conflicts between national policy objectives are also a source of government instability which imposes costs on business. During the early 1970s environmental concerns led to the conversion of coal-fired generating plants to oil. Later, in response to both drastic changes in oil prices and national energy policy embodied in legislation, oil-fired plants were converted, in some cases reconverted, to burn coal. Now, national policy choices being made by the Interstate Commerce Commission regarding coal freight regulation are threatening to make the latest round of conversions inappropriate and raising pressures to convert again back to oil.

Conflicts between national policy objectives are also a source of government instability which imposes costs on business.

Regulatory changes are not the only government actions which may make past investment decisions inappropriate for today. Tax policy changes can have the same effect. Recent tax changes show especially well how much the tax aspects of an investment decision can change in a short time. In 1981 the Economic Recovery Tax Act (ERTA) made major changes in tax laws to encourage capital formation and saving. Because of evidence of low productivity and insufficient capital formation, Congress decided that a tax stimulus for investment and economic recovery was needed. The creation of an accelerated cost recovery system, changes in the use of investment tax credits, and other provisions of ERTA provided electric utilities $2–4 billion in benefits for investment purposes. Yet, in the following year, 1982, the Tax Equity and Fiscal Responsibility Act cut these expected benefits in half.[12]

These examples of regulatory and tax policy indicate how important it is to maintain stability and harmony among national objectives. Instability nullifies otherwise optimal decisions of the past. Lack of harmony inhibits adjustment to new goals. Take the case of nuclear licensing. The length of the licensing process imposes substantial costs. Now, consider these costs in the context of a macroeconomic policy which results in high interest rates. Add to this the knowledge that 60 percent of the cost of a nuclear plant is in the cost of money. It quickly becomes clear that the micro objectives of nuclear licensing policy and the macro objectives of monetary and fiscal policy act so as to raise the cost of electric

power. If micro and macro policy were working in harmony, incentives resulting from macro policy would facilitate the availability of investment capital required for micro objectives.

Government policy toward research-and-development expenditures, public and private, also merits examination. Recent studies indicate that 10 to 20 percent of the productivity slowdown is due to insufficient R&D.[13] Clearly, a source of productivity in the future will be the innovations which flow from today's R&D expenditures. Capital investment will embody the range of technology choices available. The range of choices is especially important as the United States proceeds into an era of slower energy and electricity growth than that experienced in the past. The nation needs not only large-scale facilities to make efficient use of domestic resources but also small-scale, modular technologies appropriate for the smaller demand increments and diverse situations characteristic of slower growth. Recent government R&D decisions have jeopardized that range. Funding for R&D associated with conservation and alternative fuel technologies was drastically cut. Large scale projects in which the government worked in partnership with the private sector were placed in jeopardy. Major projects were dismantled. This instability has made the electricity R&D community wary of the role of government and the politicization of energy development. If the government proves to be an unreliable partner in long-term R&D, then the private risks and uncertainties associated with such expenditures may severely limit the public benefits otherwise attainable.

Based on the experience of the electric utility industry, it is clear that productivity, capital formation, and government actions are inextricably linked.

Based on the experience of the electric utility industry, it is clear that productivity, capital formation, and government actions are inextricably linked. These linkages cannot be broken, but they can be made a lot less counterproductive. On the micro level, the benefits and costs (direct and indirect) of any regulatory or other action should be assessed. On the macro level, the balance between consumption and investment should be shifted toward investment. To the extent that the government can reduce the instability of its policies affecting investment decisions and assure that adequate capital is available for public and private investment, productivity will be enhanced. □

Notes

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Electric Utility Operating Income Up 10.2 Percent; Earnings Per Share Up 6.9 Percent

Investor-owned electric utility operating income increased 10.2 percent in the quarter ending June 30, 1983, over the second quarter of 1982, while earnings per share were up 6.9 percent to 62 cents. Earnings per share for the 12 months ending June 30, 1983, were unchanged from the same period a year earlier at $2.82. (Table 1.)

Net extraordinary losses reduced earnings per share by 2 cents for both the quarter and 12 month period ending June 30, 1983. Even so, the 6.9 percent increase marked the first quarterly increase since the third quarter of 1982.

Electric utility operating revenues increased 4.5 percent in the second quarter as rate increases granted during earlier quarters, as well as revenues from improved industrial sales in some parts of the country, were partially offset by the lagging effects of the recession in other parts of the country, milder weather, and by lower fuel adjustment provisions due to lower fuel costs.

Second quarter electric utility operating expenses were also up 3.3 percent. Fuel costs, which accounted for 43 percent of operating expenses during the second quarter of 1982, fell to 39 percent for the second quarter of 1983. Other operation and maintenance expenses increased by 8.3 percent for the lowest quarter-to-comparable-quarter percent increase since Edison Electric Institute began tracking these expenses in 1977.

Equity Income and Shares Outstanding Increase

Assisted primarily by increased allowance for funds used during construction (AFUDC) and by moderating interest rates, net income available for common equity increased 17.9 percent in the second quarter with the total number of shares outstanding up 10.1 percent over the same period a year ago.

Total AFUDC increased 20.7 percent, accounting for 68.9 percent of net income available for common compared with 67.3 percent in the second quarter of 1982. Interest coverage ratios before income taxes and with AFUDC for the 1983 and 1982 second quarters were 2.63 and 2.38 times respectively. Coverage for the 12 months ending June 30, 1983, was 2.79 times—up from 2.65 times for the same period a year earlier.

Total industry capitalization increased $23.1 billion, or 9.7 percent, from June 30, 1982, to June 30, 1983. (Table 2.) The industry equity ratio increased to 39.5 percent from 39.4 percent on March 31, 1983, while the ratio of long-term debt to total capitalization decreased to 48.7 percent from 48.8 percent three months earlier. Short-term debt, primarily in response to declining interest rates on long-term debt, declined to 20.3 percent over the 12 months ending June 30, 1983.

Total accumulated deferred income taxes (ADIT) increased $3.2 billion, or 18.8 percent, in the 12 months ending June 30, 1983. However, total ADIT declined $324 million, or 1.6 percent, in the 1983 second quarter.

Tables 1 and 2 are based on unaudited reports received from electric utilities. The utilities account for about 95 percent of the industry's revenues from sales to ultimate customers and 94 percent of the industry's total assets. The data was expanded to represent the entire industry. □

Contributed by the Finance Department of Edison Electric Institute.

Table 1
INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY
STATEMENT OF INCOME
(Unaudited)
(Millions of Dollars)

	Three Months Ended			Twelve Months Ended		
	June 30,		%	June 30,		%
	1983	1982 (R)	Change	1983	1982 (R)	Change
Total Electric Operating Revenues	$24,772	$23,713	4.5	$102,618	$98,722	3.9
Electric Operating Expenses						
Fuel	8,026	8,541	(6.0)	34,796	37,501	(7.2)
Other Operation & Maintenance Expenses	6,739	6,224	8.3	25,852	23,079	12.0
Depreciation & Amortization	2,004	1,844	8.7	7,812	7,162	9.1
Taxes Other Than Income Taxes	1,865	1,737	7.4	7,404	6,917	7.0
Income Taxes (Federal & Other)	121	449	(73.1)	2,878	3,001	(4.1)
Provisions For Deferred Income Taxes-Net	1,177	375	213.9	3,056	1,760	73.6
Investment Tax Credit Adjustments-Net	436	545	(20.0)	2,045	1,891	8.1
Total Electric Operating Expenses	20,368	19,715	3.3	83,843	81,311	3.1
Electric Utility Operating Income	4,404	3,998	10.2	18,775	17,411	7.8
Other Utility Operating Income	282	277	1.8	1,013	1,093	(7.3)
Total Utility Operating Income	4,686	4,275	9.6	19,788	18,504	6.9
Other Income & Deductions—Net	379	437	(13.3)	1,456	1,796	(18.9)
Allowance For Other Funds Used During Construction	1,254	963	30.2	4,593	3,470	32.4
Total Income	6,319	5,675	11.3	25,837	23,770	8.7
Interest On Long-Term Debt	3,081	2,858	7.8	11,977	10,890	10.0
Other Interest Expenses & Charges	289	416	(30.5)	1,240	1,655	(25.1)
Allowance For Borrowed Funds Used in Construction (Cr.)	(795)	(735)	8.2	(3,074)	(2,813)	9.3
Total Interest & Charges	2,575	2,539	1.4	10,143	9,732	4.2
Net Income Before Extraordinary Items	3,744	3,136	19.4	15,694	14,038	11.8
Extraordinary Items	(74)	11	—	(86)	127	—
Net Income	3,670	3,147	16.6	15,608	14,165	10.2
Preferred Stock Dividends Declared	694	623	11.4	2,632	2,378	10.7
Net Income Available for Common	2,976	2,524	17.9	12,976	11,787	10.1
Common Stock Dividends	2,520	2,211	14.0	9,512	8,239	15.5
Retained Earnings	456	313	45.7	3,464	3,548	(2.4)
Earnings Per Share*	$ .62	$ .58	6.9	$ 2.82	$ 2.82	(0.0)
Dividends Per Share*	$ .53	$ .51	3.9	$ 2.06	$ 1.97	4.6

*Based on average shares collected quarterly from respondents and adjusted for stock splits.
(R) Revised
NOTE: The income statement is a "net" or "consolidated" statement. The duplicative effect of including resale revenues by one investor-owned electric utility to another has been eliminated.

Table 2
INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY
Balance Sheet
(Unaudited)
Report as of June 30, 1983 and 1982

ASSETS	(Millions of Dollars) 1983	1982	Change (%)
Utility Plant*			
Utility Plant (Including Nuclear Fuel)	$262,060	$240,488	9.0
Less Accumulated Depreciation	73,997	67,044	10.4
Less Property-Related Accumulated Deferred Income Taxes	3,641	3,017	20.7
Total	$184,422	$170,427	8.2
Construction Work in Progress	96,128	85,576	12.3
Net Utility Plant	$280,550	$256,003	9.6
Investments	6,133	5,556	10.4
Current Assets	30,943	29,217	5.9
Deferred Debits	8,024	6,749	18.9
Total Assets	$325,650	$297,525	9.5
CAPITALIZATION & LIABILITIES			
Capitalization			
Common Stock	$ 70,526	$ 62,399	13.0
Retained Earnings	32,370	29,134	11.1
Preferred Stock	30,661	28,470	7.7
Long-Term Debt	126,757	117,241	8.1
Total Capitalization	$260,314	$237,244	9.7
Current Liabilities			
Short-term Debt	$ 5,940	$ 7,456	(20.3)
Long-term Debt Due Currently	3,822	3,643	4.9
Other Current Liabilities	22,270	20,816	7.0
Total Current Liabilities	$ 32,032	$ 31,915	0.4
Deferred Credits			
Accumulated Deferred Income Taxes	$ 16,459	$ 13,896	18.4
Accumulated Deferred Investment Tax Credits	11,146	9,256	20.4
Other Deferred Credits	5,699	5,214	9.3
Total Deferred Credits	$ 33,304	$ 28,366	17.4
Total Capitalization & Liabilities	$325,650	$297,525	9.5

*Includes other utility plant of combination gas and electric companies.

Coal Water Slurry

It has the texture of a thin latex paint. In the bright sun, it looks like chocolate syrup. But it's really a promising fuel known as coal-water slurry (CWS).

For many electric utilities and industrial companies, CWS may prove to be an effective alternative to fuel oil, which is costly and at times has been in short supply.

Because CWS can be made easily at a relatively low cost, the Electric Power Research Institute (EPRI) and the U.S. Department of Energy, along with several utilities and commercial companies, have supported the development of CWS, which began in the 1970s.

CWS consists of finely crushed coal mixed with water and a small amount of additives. The mixture is 70 percent coal; 29 percent is water; and the rest consists of the additives that give CWS the physical characteristics to permit its being transported and handled like No. 6 boiler fuel—the mainstay of oil-fired electric utility power plants.

EPRI Project Manager Rolf Manfred notes that unlike regular pulverized coal, which requires storage and handling facilities, CWS can be shipped in railroad tank cars and pumped into storage tanks just like oil.

"If current programs under way at EPRI prove successful, utilities will have an alternative by the mid-1980s," Manfred says. "CWS is attractive to utilities with coal-fired boilers that now burn oil and where reconversion back to coal is impractical. It should also help reduce dependence on foreign fuel supplies, as well as save money."

CWS is not without its limitations, however. "A lot of work needs to be done," Manfred says. For example, burners to resist erosion caused by the additives in CWS must be developed. A first generation of nozzles has been adequate to burn the slurry with a stable flame, but a second generation must be engineered to fire CWS in finer droplets without having erosion occur. And these burners must be large enough to be used by electric utilities. Also, because of its water content, CWS causes boilers to operate 4 percent less efficiently than they do when they burn pulverized coal in the conventional way.

Nevertheless, potential advantages outweigh disadvantages. CWS does not have to be dewatered before being fired, and with the large domestic supply of coal at hand, customers would be guaranteed a stable fuel source. Moreover, most of the ash and some of the sulfur can be washed out of the coal during the preparation process for a cleaner exhaust at the back end of the burning.

Memphis Test

CWS research is moving ahead at EPRI to advance its development for commercial use as well. A 35-day handling and combustion demonstration conducted during August and September 1983 at the DuPont Company's Memphis plant was highly successful according to Manfred and other participants. "The test firing demonstrated that CWS can be manufactured on a semi-commercial scale, and that it can be transported over considerable distances in tank cars without problems, such as settling." The slurry showed no settling in transportation or storage for up to 14 weeks as the additives kept the coal particles suspended in the water, showing good flow characteristics. The CWS was drawn off of tank cars into a 5,000 gallon tank truck and taken to a 15,000-gallon agitated storage tank, before it was fed to the boiler for the test.

The Memphis test, when about 2,400 tons were burned in continuous firing, was the largest and longest CWS burning in a sizeable boiler to date. A 65,000 pph steam boiler was used. It contained five Babcock and Wilcox burners, each rated at 15 million Btu/hr. Full or needed loads were achieved by firing slurry in three burners, with the other burners turned off. The slurry burned steadily, without supplementary fuel at rates as low as 20 million Btu/hr. A natural gas assist, contributing 5 percent of the energy, was maintained for operational reasons. The

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firing encountered only minor difficulties normal to a test project.

The Memphis test followed a successful test burn in the fall of 1982 at an 80-million Btu/hr, full-scale burner facility in Windsor, Connecticut.

Cost Factors

Researchers believe that CWS will be cheaper to burn than No. 6 boiler fuel-oil, even at current prices, depending on the specific conditions encountered by individual utilities. Estimates made in 1982 by EPRI show that the projected fuel cost for CWS, manufactured in a plant at the rate of 1 million tons per year, is about $3 to $3.50 per million Btu, which compares favorably with typical current costs of $4 to $4.50 per million Btu for No. 6 boiler fuel.

The $3 to $3.50 cost includes about $1.60 per million Btu for the coal and about 80 cents per million Btu for slurry preparation. Cleaning the coal down to 4 percent ash weight can add another 50 cents per million Btu, and the balance is for transporting the coal by rail from the mine to a coastal slurry preparation plant and for miscellaneous costs.

Part of the cost advantages of CWS, however, are offset when a utility plant is modified to burn it. Site-specific costs to convert an oil-fired utility plant from oil to CWS, Manfred says studies show, are in the range of $100 to $300/kWe. For a furnace designed for oil, modifications may include the addition of a steeply sloped furnace hopper bottom, wall deslaggers, new burners, and ash removal and collection equipment.

Technology Advancing

"CWS technology has now advanced to the point where near-term commercialization is possible," Manfred says. "Commercial utility acceptance can be accelerated by demonstration tests in utility boilers.

"However, to support tests of the necessary size and duration requires a much larger CWS supply capability than now exists. Currently, a variety of interested participants are seeking to construct such a capability." EPRI, in addition to the Memphis testing, is involved in a number of other CWS projects.

The United States is not the only country where CWS R&D efforts are occurring. Canada, Japan, Italy, and Sweden are experimenting with the mixture with varying results, and several vendors are joining with these countries to pursue commercialization of the technology. □

Coal-water slurry, above, is an attractive fuel alternative which can be made easily and at a relatively low cost.

Reductions in Planned New Capacity Continue

Since 1975, the industry's long-term forecasts of generating capacity have been coming down. The total scheduled backlog of future installations in the industry's expansion program reached a record level of over 310 gigawatts at the end of 1974, but dropped to 300 gigawatts in 1975, and by the end of 1982 was down to 140 (Table 1). The decline can be attributed to two major factors: removal of planned projects from the schedule, and the fact that the amount of capacity installed during each of the years (1975–1982) exceeded the new capacity ordered.

The industry's forecasts of planned new capacity have been made largely in response to successive decreases in projected long-term peak-demand growth. As compiled and reported by the North American Electric Reliability Council, the ten-year projection made in 1972 stood at 7.6 percent; by 1983 it had dropped to 2.8 percent. These reductions in projected demand can be attributed in turn to the cumulative experience of less than expected demand growth during the last several years, increased utilization of load management and conservation techniques, and a decline in the rate of projected economic growth.

Because it takes 10 to 12 years to plan and bring a new generating plant online, successive decreases in long-term demand projections have caused many generating units placed in the schedule during earlier periods of higher load growth expectations to be postponed or even cancelled. Additionally, an appreciable amount of new capacity has been cancelled or deferred because of the financial constraints faced by the electric utility industry. During 1982 alone, 24 steam turbine-generators totaling 20 gigawatts, were removed from the planning schedule and 33 units totaling 24 gigawatts were delayed one year or more. □

Contributed by the Statistics Department of Edison Electric Institute.

Table 1.
Orders, Removals from Schedule, Installations, & Year-End Backlog
U.S. Electric Power Systems
Megawatts by Prime Mover
1975–1982

Year	Prime Mover	MW Ordered	MW Removed From Schedule	MW Installed	Year-End Scheduled Backlog
1975	Fossil STG's	5,989	1,897	20,895	122,438
	Nuclear STG's	6,213	11,051	7,396	157,662
	Comb. Turbs.	4,259		3,917	6,012
	Hydro	1,458		2,232	13,535
	Total	17,919		34,440	299,647
1976	Fossil STG's	6,786	4,406	11,685	111,003
	Nuclear STG's	8,465	2,414	4,822	162,122
	Comb. Turbs.	1,620		2,285	6,488
	Hydro	2,961		1,629	14,796
	Total	19,831		20,421	294,409
1977	Fossil STG's	13,602	1,696	18,072	102,538
	Nuclear STG's	—	7,913	6,609	147,442
	Comb. Turbs.	1,240		1,713	5,649
	Hydro	1,596		1,131	15,227
	Total	16,438		27,525	270,856
1978	Fossil STG's	18,333	1,183	13,971	103,256
	Nuclear STG's	—	7,242	3,029	137,169
	Comb. Turbs.	673		1,671	3,380
	Hydro	1,099		4,058	12,352
	Total	20,105		22,729	256,157
1979	Fossil STG's	4,479	2,122	12,332	98,996
	Nuclear STG's	—	14,168	1,156	116,038
	Comb. Turbs.	429		773	2,605
	Hydro	969		2,934	8,839
	Total	5,877		17,195	226,478
1980	Fossil STG's	2,846	3,902	18,709	83,005
	Nuclear STG's	—	10,587	1,885	109,383
	Comb. Turbs.	551		510	2,485
	Hydro	15		1,302	7,708
	Total	3,412		22,406	202,581
1981	Fossil STG's	7,920	3,511	9,777	81,177
	Nuclear STG's	—	24,593	4,427	79,682
	Comb. Turbs.	525		714	1,437
	Hydro	209		259	7,694
	Total	8,654		15,177	169,990
1982	Fossil STG's	93	11,524	11,057	61,887
	Nuclear STG's	—	8,693	1,183	70,222
	Comb. Turbs.	36		389	1,385
	Hydro	279		607	6,288
	Total	408		13,236	139,782

Source: EEI Electric Power Survey data

The Next American Frontier

Robert Reich
Times Books, 1983
New York, New York, 324 pp.

By Sue Lerner

In *The Next American Frontier,* Robert Reich joins his Harvard colleagues in the battle for a national industrial policy currently being waged in professional literature, the media, government, and in the rhetoric of the coming national elections.

Reich is a professor of public policy at Harvard's John F. Kennedy School of Government and, in a former life, was director of public policy planning for the Federal Trade Commission. He is also co-author of *Minding America's Business* and a regular contributor to *The New Republic* as well as other publications.

In this latest work, Reich provides background for his position on an industrial policy by presenting a synthesis of our country's recent social, political, and economic history—as he perceives it—concluding that the shift of competitive advantage in mass produced goods from the United States to other nations such as Japan and West Germany is a result of their lower labor costs and better access to materials and new markets. He says this shift has seriously eroded aspects of the United States' economic base. The net result, according to Reich, is that we need to seek a transformed industrial base to achieve a new competitive advantage based on our inventory of managerial and labor supply skills.

The current argument evolving for a national industrial policy is based on the concept that a policy would provide an opportunity to optimize the relationship among government, industry, and the supporting communities. This argument has supporters and detractors from almost every avenue of interest including the academic community, legislators, politicians with national ambition, and those who see in the Japanese experience the guideposts for success, as well as those who don't.

Reich joins the argument with superb credentials—both academic and governmental. Thus, his contribution merits serious consideration. Of Reich's book, Walter Mondale says it is "One of the most important works of the decade. The historical sweep of the analysi and the intellectual rigor of the diagnosis are truly remarkable." Senator Gary Hart comments, "Few books on economics are bold enough to capture one's imagination. This is one. Mr. Reich's admonition that we must adapt and his penetrating insight on how to adapt should be heeded. Nothing less than America's economic future is at stake." And Daniel Yergin, Reich's Harvard colleague, states, "A provocative and compelling book. It is likely to be controversial. It could not be more timely."

And timely it is because at this very writing the media is filled with the argument on industrial policy.

Reich believes that American national life is divided into two broad categories. One is that of government and politics; the other is that of business and economics. And the two do not intermingle to a great degree. Questions of social justice (government), according to Reich, can no longer be separated from questions of economic growth and development (business). The horns of the dilemma on which we risk being impaled, as a nation, are the perhaps conflicting requirements of the two categories. The government-inspired socia welfare orientation requires increasing expenditures. Some analysts feel those expenditures are short-sighted for they are being allocated at the expense of adequate resources for business investment. Their argument runs that if business investment came first, it would provide adequate employment opportunities, which would circumvent the need for certain social expenditures. To achieve the dual goals of adequate "social justice" and adequate development of resources for business investment, Reich concludes that labor, business, and government must work together with the long term, not simply the short term, in mind. It is a "New World" that

Sue Lerner is Director of Corporate Planning for Edison Electric Institute.

America must adapt to, and Reich provides guidelines for this adaptation.

He states his premise succinctly: "Americans whose principal frame of reference is the civic culture charge business with undermining civic values by compromising politicians with campaign contributions, polluting air and water, and endangering workers and consumers. Americans whose principal frame of reference is the business culture feel that government and politics intrude mischievously on the free market, at best distracting businessmen from the vigorous pursuit of national prosperity, at worse subverting the system of individual enterprise."

Reich answers this statement by saying, "This choice is falsely posed. In advanced industrial nations like the United States, drawing such sharp distinctions between government and market has long ceased to be useful. . . . [T]he interwoven organizations of government, business, and labor together determine how America's resources are allocated and employed. Public and private spheres are becoming indistinguishable."

Reich's premise about the management of resources is that productivity and economic growth no longer depend on the overall level of investment as much as they depend on how investment is used. Looking toward efficient management of resources in a free market situation, he concludes that America's decline has resulted from its failure to recognize what he describes as the "new economic realities" that require government, business, and labor to integrate their decisions regarding the management of resources.

In analyzing the history of America's industrial development, Reich identifies America's development and productivity as the direct evolution of the developments of Britain's industrial revolution. To these developments great quantities of investment capital, available labor, and access to a very large indigenous market were added. The resulting productivity grew at a rate in excess of that of any other industrialized nation. This growth occurred prior to World War I when there were problems, bottlenecks, inefficiencies,

and other impediments to optimization of production and distribution.

But this period was followed by what Reich describes as the era of management—post-World War I through 1970. During this period, according to Reich, the idea of "the fruits of high volume standardized production" evolved. Managed organizations, providing "stability, order, and prosperity" became the norm not only in business, but in government agencies and labor unions as well. The net result was an efficiency that maintained its level for more than 50 years before things began to change drastically in the 1970s.

Reich describes this 50-year period as a time when "managerialism offered America a set of organizing principles at precisely the time when many Americans sensed a need for greater organization. And these principles soon shaped every dominant American institution precisely as they helped those institutions become dominant. The logic of routine, large-scale manufacturing first shaped its original business environment and then permeated the larger social environment. And American society embraced and duplicated it because it was the very engine of prosperity."

What differentiated economic activity in the United States from that in continental Europe and Japan was the place of government in the production mix. In Europe and Japan the governments pushed for economic development and cooperated in this activity. In the United States this relationship did not eventuate. Reich remarks that by the 1960s "European and Japanese governments and banks were carefully monitoring changes in world markets, helping their firms line up sources of supplies, and arranging export financing." Reich concludes that this direct intervention was designed to push their economies to grow.

Also, the European development was towards organizations of single purpose rather than organizations which diversified. Diversification through mergers and acquisitions was commonplace in England during the 1970s, as it was in the United States. During this same period emphasis in the Common Market by and large was on industrial organizations that produced commodities having some relationship to one another. In the United States, however, the nature of diversification resulting from mergers and acquisitions negated this opportunity for optimizing managerial and other skills and opportunities.

Reich traces the development of social welfare programs in European countries and in Japan and describes them as integrated, or at least connected, with economic health and productivity. He ascribes this integration to the fact, as he sees it, that Britain and America had not experienced the kind of devastation during World War II that Europe and Japan had experienced. Consequently, the need for post-war social and economic reconstruction differed among these nations. He argues that in Britain and the United States there was an ideological and institutional distinction that separated concepts of social welfare from concepts of industrial development. This separation, according to Reich's analysis, is exemplified in the complaints from business that government regulation and non-productive expenditures for environmental controls, inflation, taxes, government subsidized imports, along with the shock that resulted from OPEC in 1973, are critical factors in our industrial decline. Reich dismisses all of these as not part of the real explanation. He also dismisses inadequate capital formation and government deficits, almost all the causes that are commonly attributed to the relative decline in U.S. productivity, as only a small part of our "gradual, steady economic decline relative to other leading nations." Reich believes that all of these reasons "fail to take into account the worldwide reorganization of production and America's failure to adapt to it." He goes on to describe the restructuring of world markets with the organization of political entities into larger groups, such as the Common Market, and with the burgeoning of industrial development in previously undeveloped countries which provide access to new labor and consumer markets. Industrialized nations, which in the past, in a sense, had cornered the market opportunities because of their skill pools, access to financing, etc., no longer have this advantage. Previously underdeveloped areas are producing the most sophisticated types of equipment because production methods have been altered and adapted to meet the economic opportunities of production in these areas.

This kind of "flexible system production" appears to have been accepted slowly by U.S. firms; it is so very different from standardized production, according to Reich, that a transition to it requires "a basic restructuring of business, labor, and government; any reorganization of this magnitude threatens vested economic interests and challenges established values and is thus bound to be resisted."

Japanese success in the world market place has brought with it envy and a desire for emulation by American business. Reich believes that American businessmen perceive excellence in management as the cause of the Japanese success, but that this perception does not go to the heart of the matter—the cooperative association among Japanese business, government, and labor. The assumption one gathers is

that our industrial base must be restructured so that a considerable portion of our basic industrial activity is in the "flexible system" mode of production rather than in the standardization mode.

Reich describes the kind of industrial activity we have seen in the last decade in the United States as "paper entrepreneurialism"—acquisitions or conglomerations that serve no useful function, he believes, since legitimate investors, should they have wanted to invest in a particular array of industries, could have purchased stocks separately. Reich also believes that paper entrepreneurialism serves no useful industrial purpose because there are no complementary operations and that it does not benefit employees because decisions are made on the basis of capital asset value. In this economic environment, workers are not typically a major consideration.

The net result of the various machinations associated with paper entrepreneurialism is that "ours is becoming a symbolic economy in which resources circulate endlessly among giant corporations, investment bankers, and their lawyers but little new is produced." This activity leads to financial resources being maintained in a liquid state to take advantage of opportunities that require rapid response. Thus, serious capital investment in productive enterprise is seriously impaired.

The basic premise underlying the author's argument is that overall organization is a requirement of the successful evolution of American industry and that this evolution is an absolute must. However, this evolution will engender major economic change and will require an equitable sharing of the resulting pluses and minuses of the change. Reich declares the issues of "social justice" to be critical to the success of this change.

In analyzing what is going on today, Reich finds that "one out of every three American workers now depends for his or her livelihood, directly or indirectly, on American industries that are losing rapidly in international competition. (e.g., textiles and automobiles.)" He sees a new era coming which he calls "the era of human capital" and describes it as "an era that all industrialized nations are entering; high volume and standardized production will to a great extent be replaced by flexible system production in which integrated teams of workers identify and solve problems."

One is tempted to say "good luck." Reich perceives this new industrial activity as more collaborative, participatory, and egalitarian than is high-volume standardized production, for the simple reason that initiative, responsibility, and discretion must be so much more widely exercised within it. One wonders whether Professor Reich has ever experienced work in the real world, in work places where people are earning a living to survive rather than participating in a cooperative exercise in investigation, origination, or intellectual pursuit of one sort or another.□

Oil! A Crude Warning

Washington State University
Foundation
Economic Forum Series
1983 30 minutes

By George Embrey

Ten years after the Arab oil embargo, Americans are forgetting the great lesson learned about the perils of the United States' long love affair with oil. Big cars are back in style. "Alternative" fuel projects are being shelved. And, with economic recovery well underway, imports of foreign oil are inching upward—35.7 percent of the U.S. petroleum supply in a recent month compared to 31.5 percent in the same month a year earlier.

Oil! A Crude Warning, a television documentary for the Public Broadcasting System comes at a good time. Sponsored by Washington State University as part of its Economic Forum Series, the telecast was produced by Vik-Winkle Productions, Inc., of Burbank, California, with assistance from KWSU-TV in Pullman, Washington. The documentary is also available for use by schools, industry, and government.

George Embrey is Washington Bureau Chief for the Columbus Dispatch.

Oil! A Crude Warning *narrator Keith Jackson, on location.*

The best thing about this effort to educate Americans about oil realities is the use of popular sports commentator Keith Jackson of the American Broadcasting Company. As narrator, Jackson keeps viewer interest between the usual sort of experts who provide documentation. He has the style and television charm to carry such heavy lines as: "Our challenge regarding oil is clear; we must find ways to satisfy our unquenchable thirst for petroleum," without sounding preachy.

Some of the best scenes in *Oil! A Crude Warning* are the still photos of how America entered the Golden Age of Oil—pictures of the first Drake well begun on August 27, 1859; gushers exploding in California; and later boomtimes in Texas and Oklahoma.

Our mobile society grew out of cheap, abundant gasoline and the vast highway systems and auto industry that make it so easy to get around. The documentary goes even further in explaining our dependency, pointing to the massive harvests of cheap fresh vegetables, beef, and poultry made possible by petroleum and its many by-products—from gasoline for the tractor to pesticides for increased yields that remain the envy of the rest of the world.

Then there's the present day reality—the October 17, 1973, Arab oil embargo that sent the price of oil skyrocketing from a cheap $2 a barrel for light Arabian crude delivered to New York, to as much as $40 a barrel on the spot market. The worldwide recession that resulted from further "oil shocks" and long years of anxiety mar even this spring and summer's robust economic recovery here in America.

In sports vernacular, Jackson edges into controversial ground, claiming that despite the constant threat of another sudden shock—more war in the Middle East, a second embargo—this country is like an athletic team playing "without a game plan."

Alan Pettibone of the Washington State University College of Agriculture tells us that modern U.S. agriculture simply could not exist without a great deal of oil. For perspective, Pettibone adds that with only 5 percent of the world's population, this country feeds 11 percent. Yet we have only a year's supply of grain in reserve and half a year's reserve of oil.

Gene Varanini of the California Energy Commission's Committee on Preparedness warns that if our high level of oil importation were ever again suddenly curtailed, we'd face two choices: a catastrophic economic slowdown, or an invitation to potential aggressors by emptying our strategic reserves. Not a pretty picture.

But there's more. Varanini develops the scenario in which foreign oil dependency has put this country in a position where, even when the nation tries to develop alternative fuels, the oil cartels merely lower their prices, rendering the production of synthetic oil and gas from coal—or solar and wind power—too expensive relatively speaking.

Rene Males of the Electric Power Research Institute, another of the documentary's experts, tells the story of how the United States has gobbled up half of its known fossil fuels such as oil in the past 200 years.

Males' scary warnings of future scarcity may fall on deaf ears. But the American Petroleum Institute recently reported that despite the apparent abundance of the current world oil supply, "By the year 2000, only 17 years

from now, more than three-fourths of the oil the United States will need will have to come from fields that have not yet been found."

Margaret Krahenbuhl, a Middle East expert for the Rand Corporation, explains how the United States cannot isolate itself from another oil cutoff in that region, although most of its imported oil comes from other sources. Under international agreement, the United States must share any scarcity in an emergency even to the point of shipping some of its own reserves to Western Europe in a worst case scenario.

What should the United States be doing now to prepare for the shock of another oil embargo or cutoff due to war or terrorism in the Middle East?

Pettibone suggests the development of "energy crops "—sources of alcohol for fuel additives and substitutes. Males looks to better use of coal and atomic power. Varanini would like our six-months' strategic oil reserve to be increased to a full year's supply. Krahenbuhl thinks the United States should have "SWAT" teams ready to deploy to the Persian Gulf oil fields to restore the flow after terrorist attacks.

The commentary is not all pessimistic; however, it does report that the United States is increasing oil production in Alaska. But the fact remains that, despite the economic recovery, about half the nation's available oil well drilling rigs are standing idle. And, unless the market price goes up substantially, the sure but slow economic recovery will not put the drillers back to work in force.

The U.S. Energy Information Administration reported recently that while total U.S. oil consumption in 1983 is running at about the same level as in 1982, projections call for a 5 percent rise in 1984, the first upswing in oil consumption since 1978.

In short, *Oil! A Crude Warning* argues that in any case, the United States has to make better use of the oil it has and wean itself from a dependence on only one fuel. But without public support, the best game plan for achieving this goal will not work.

Consequently, those experts who know what's going on believe the education of the public now, not later, is a must.

An excellent report has been published recently on why it is that the American Public appears to uninformed in such crucial matters. John Robinson, director of the Survey Research Center of the University of Maryland and Mark Levy, a UM journalism professor, report that a Maryland national opinion survey shows how difficult it is for the media to inform the public and for the public to keep up with what it needs to know. "The public is neither stupid nor uninterested in the news," they say, "but it is busy and easily distracted."

That may be why it takes a big time television sports announcer, a polished production, and convincing experts to make a successful documentary to get the oil warning across.

Oil! A Crude Warning meets that responsibility in excellent fashion.

Note: Oil! A Crude Warning *is available for preview and purchase in 16mm and video formats. Specify ¾", VHS, or Beta when ordering. Call or write Gale Franko, KWSU-TV, Murrow Center, Washington State University, Pullman, Washington, 99164-2560; telephone, 509/335-8111.* □

Hydroelectric Relicensing

Another chapter has been written in the ongoing debate concerning whether a municipal preference applies to the relicensing of hydroelectric projects under the terms of the Federal Power Act (FPA). (See "Now And In The Future," *Electric Perspectives*, Fall 1983.) On October 6, 1983, the Federal Energy Regulatory Commission (FERC) issued Opinion 191, reversing the administrative law judge's decision in what is popularly referred to as the *Merwin* case. FERC voted unanimously to award a new license for the Merwin project to Pacific Power & Light Company (PP&L), the existing licensee, finding that:

> In this instance, the economic implications of the alternative licensing actions clearly weigh in favor of allowing the power benefits of the Lewis River at Merwin to remain with the segment of the public served by PP&L. (Opinion 191, p. 47.)

Before reaching its determination with respect to the new license, however, FERC, on a 3-2 vote, overruled its 1980 decision in the *City of Bountiful* case, Opinion 88, issued June 27, 1980. FERC held that a municipal preference does not apply on relicensing against existing licensees.

The Merwin proceeding arose when the Clark-Cowlitz Joint Operating Agency (JOA), qualifying as a municipality under the terms of the FPA, filed a competing application for a new license to operate PP&L's Merwin dam project in southwestern Washington. PP&L had been operating this 136 MW project under a 50-year license issued to a predecessor in 1929. In 1976, three years before the license was due to expire, PP&L applied under the FPA for a new license to continue to operate and maintain the project. Then, in 1977 the JOA filed a competing application for a new license to acquire, operate, and maintain the Merwin Project. The JOA claimed a municipal preference under section 7(a) of the FPA.

On November 22, 1983, by granting their requests to participate before FERC but denying all applications for rehearing, FERC has enabled the American Public Power Association, certain municipalities, and the Edison Electric Institute to participate as parties in subsequent judicial proceedings. An appeal will now undoubtedly be taken to the U.S. Court of Appeals for either the District of Columbia Circuit or the 9th Circuit. Whatever the outcome at that level, parties to the case will likely seek review by the U.S. Supreme Court. Thus, final judicial review is unlikely for at least two years.

An interesting legal issue in the upcoming Merwin proceedings will be whether FERC could lawfully overturn its earlier Bountiful holding. Citing cases supporting the proposition that an agency is not bound by its earlier error and that it has the power to correct such errors, FERC found that it was not bound by the earlier interpretation, the subsequent approval by the U.S. Court of Appeals for the 11th Circuit notwithstanding. FERC observed that the 11th Circuit gave "great deference to the Commission's statutory interpretation" and then reasoned that the 11th Circuit may have been inadvertently misled by FERC's earlier Bountiful decision. This issue has been raised in the applications for rehearing and will undoubtedly be argued vigorously when the case moves to the courts.

In rejecting the finding of the administrative law judge in his initial decision, FERC found that the economic impacts of an adversary licensing action are an appropriate area for public interest consideration. "If the public interest favors the consumers served by a private entity, Sections 7(a) and 10(a) require the license to be issued to that entity to permit its consumers to receive the benefits." (Opinion 191 p. 39.)

FERC then examined the public interest considerations prevailing today in contrast to those of 1920, as they relate to justification for the municipal preference concept. Concluding its review of developments during the intervening 60 years, FERC stated:

> . . . we find it impossible to continue to see privately owned electric utilities in the eyes of Gifford Pinchot as 'water power grabbers' who are 'eager for plunder.' *We see them, instead, as regulated entities serving segments of the public, just as public power entities serve other*

Contributed by Edison Electric Institute Deputy General Counsel Peter Kelsey.

segments of the public. As a result, we believe that the Part I public interest in the ultimate public ownership of water power sites is considerably weaker today than in 1920. As a further result, we believe that the focal point of the Part I public interest today is the impact on consumers of choosing between an 'original licensee' in possession of project works, and a 'new licensee' . . . (Opinion 191, p. 45) (Footnotes omitted.)

FERC's unanimous vote to award the new license to PP&L turned on an analysis of the economic impacts associated with the relicensing. Whereas the Clark and Cowlitz JOA serves only 118,200 customers, FERC found that PP&L serves 643,400 customers. Thus, approximately six customers would suffer from the loss of the Merwin project for every one customer that would benefit. A comparison of the power-cost consequences found that PP&L's power cost would increase by $3.42 for each $1 savings in the JOA's power costs. In terms of net revenue requirements, PP&L's would increase by $8.92 for each $1 decrease in the JOA's net revenue requirements. Based on these and other factors discussed in the opinion, FERC voted unanimously to award the new license to PP&L.

In addition to further consideration of the relicensing preference issue which will occur in the courts, a bill has been introduced in Congress which will prompt congressional consideration of this important public policy question. On November 16, 1983, Congressman Richard C. Shelby and 44 co-sponsors introduced H.R. 4402, (129 *Congressional Record* E5700 [Daily Edition, November 18, 1983]), the Electric Consumer Protection Act of 1983. This bill, by amending sections (7(a) and 15(a) of the FPA, would clarify relicensing procedures and provide just compensation for existing licensees, should a new license for an existing project be awarded at expiration to a new licensee.

H.R. 4402 would clarify the licensing procedures by providing for the issuance of a new license to an existing licensee, whether it be a private or public utility or other licensee, unless FERC were to find that the licensee's project, as described in its application for a new license, would not meet the licensing standards of section 10(a) of the FPA. In making this determination, FERC would be authorized to take into consideration the public benefits conferred during the preceding license term. The effect of this would be to require that the project "be best adapted to a comprehensive plan . . ."

FERC would retain its present authority to include terms and conditions in the new license as authorized or required under laws and regulations in existence at the time of relicensing. Only if FERC were to find that the existing licensee's project did not meet the section 10(a) requirements, or if the existing licensee did not want the new license as conditioned, would it be subject to competitive applications.

The bill would change the current law with respect to compensation for the existing licensee, should a new license for its project be issued to another licensee. The present standard, net investment plus severance damages, applicable through section 14 of the FPA, would be replaced by a just compensation standard as determined by FERC in accordance with due process of law. The net investment standard, which has been interpreted to be only the original cost of the plant 50 to 60 years ago depreciated over the life of the license. The standard in H.R. 4402 would provide fair compensation to the existing licensee and its customers for the loss of future use of the hydroelectric project and the many benefits flowing from it.

As has been suggested in the course of the Merwin proceedings before FERC, whether municipal preference should apply to the relicensing of hydroelectric plants is a fundamental public policy determination. It is one which should be made by Congress under today's circumstances, rather than by a judicial interpretation of statutory language enacted by Congress under circumstances that prevailed more than 60 years ago. As FERC recognized in Merwin, significant changes have occurred in the intervening years which make the relicensing issue truly a consumer issue, rather than a debate over the virtues of public and private power development. □

CALENDAR OF MEETINGS
Edison Electric Institute

When
What
Where
Who to Contact
(Call 202/828-7400)

December 12–14
A.G.A.-EEI General & Plant Accounting Committees
Clearwater Beach, Florida
George Brown

January 17
EEI Codes & Standards EAC
Atlanta, Georgia
John Markey

January 22–24
EEI Rate Research Committee
Atlanta, Georgia
David Owens

January 24–26
EEI Quality Assurance Committee
Birmingham, Alabama
Suzanne Phelps

January 24–27
EEI Transmission & Distribution Committee
Miami, Florida
David Soffrin

January 25–27
EEI Environment & Energy Committee
Atlanta, Georgia
Victoria Hull

January 29–February 1
EEI Prime Movers Committee
New Orleans, Louisiana
James Evans

February 5–8
EEI System Planning Committee
Albuquerque, New Mexico
Jamei Goellner

February 6–7
EEI Commercial/Industrial Committee
Tampa, Florida
Charles Taylor

February 9–10
A.G.A.-EEI Information Systems Committees
Sarasota, Florida
Ralph Palmigiano

February 12–15
A.G.A.-EEI Depreciation Accounting Committee
West Palm Beach, Florida
George Brown

February 13–15
EEI Electrical System & Equipment Committee
Denver, Colorado
Jamei Goellner

February 22–24
A.G.A.-EEI Budgeting & Financial Forecasting Committees
New Orleans, Louisiana
Lowell Klosky

February 22–24
EEI Personnel Research Task Force
Los Angeles, California
David Kleinke

February 28–March 1
EEI Engineering & Operating Division Computer Committee
New Orleans, Louisiana
Martin Gordon

March 5–6
EEI Economic Development Subject Area Committee
Alexandria, Virginia
Charles Taylor

March 12–13
EEI Street & Highway Lighting Task Force
Alexandria, Virginia
Charles Taylor

April 4–7
EEI Legal Committee
San Diego, California
Robert Baum

April 10–12
EEI Affirmative Action Seminar & Workshop
Atlanta, Georgia
Ed Bomsey

April 16–18
EEI Construction Committee
St. Louis, Missouri
Eric Haskins

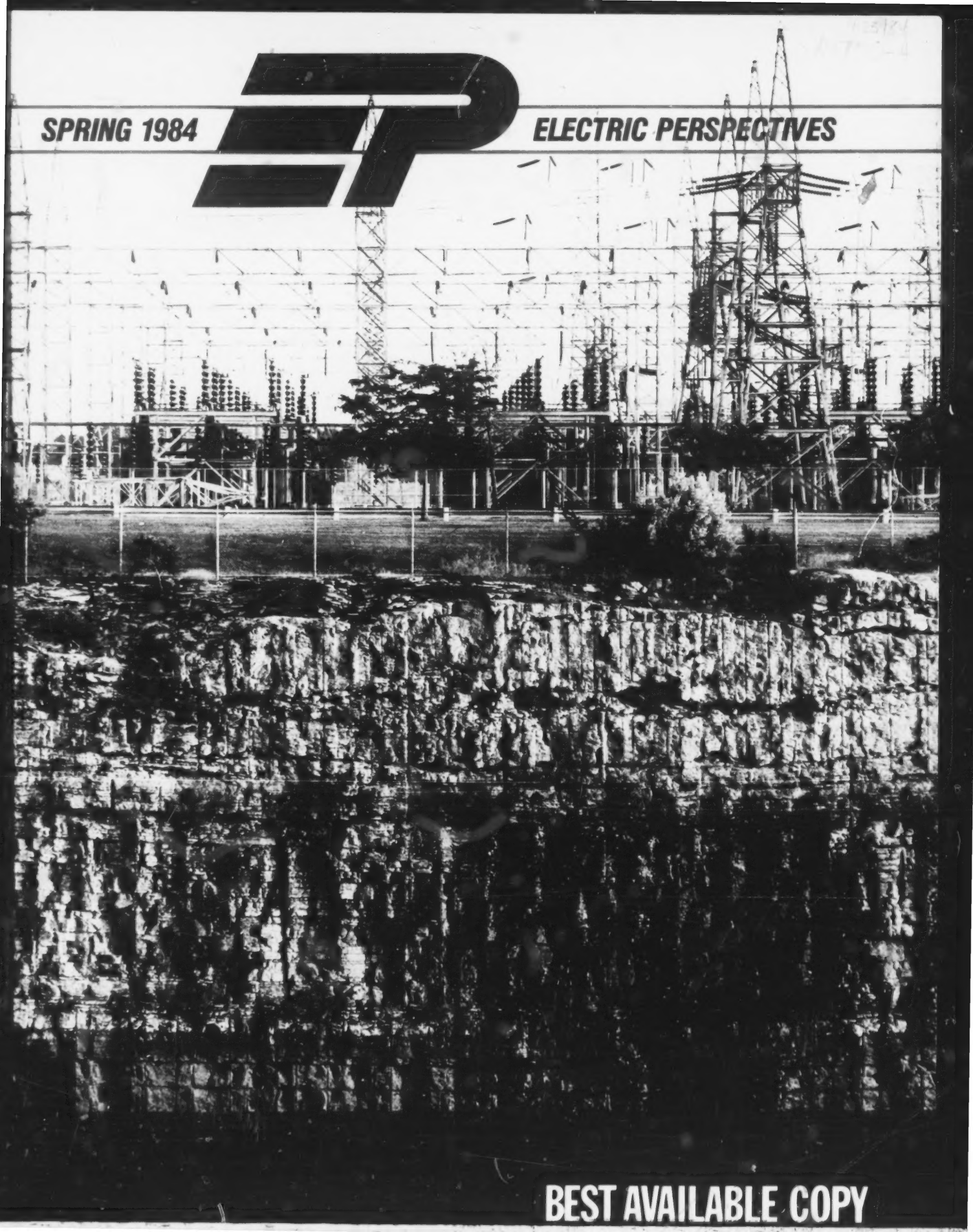
April 17–19
EEI Quality Assurance Committee
Little Rock, Arkansas
Suzanne Phelps

April 25–27
EEI Interconnection Arrangements Committee
Columbus, Ohio
Martin Gordon

April 28–May 2
EEI Prime Movers Committee
Miami, Florida
James Evans

April 29–May 1
EEI Rate Research Committee
Buffalo, New York
David Owens

May 7–9
EEI Safety & Industrial Health Committee
Cincinnati, Ohio
Melodye Turek



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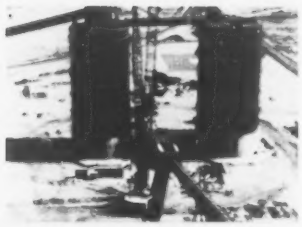

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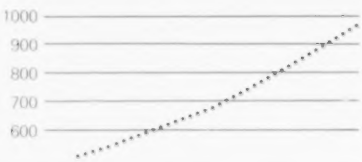

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COMING OF AGE AT COOL WATER

Coal gasification-combined cycle power generation technology soon begins full-scale demonstration.

By Marie Mastin Newman

Marie Mastin Newman is a writer and communication consultant specializing in energy issues.

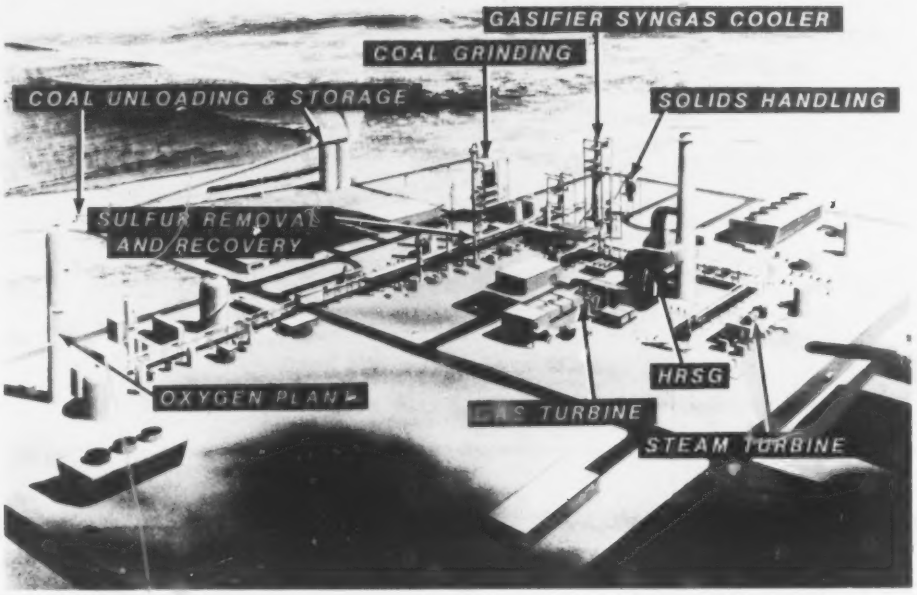
Attention in the utility industry will be directed West to California's Mojave desert this fall when formal demonstration will begin of a major new energy technology that many in the industry believe will be vital to the use of coal for electricity production in the 1990s and into the new century. There, in Daggett, California, at Southern California Edison Company's (SCE) Cool Water Generating Station, a new kind of power plant will begin to produce electricity by what is known as the integrated coal gasification-combined cycle, or IGCC, process. The plant, which represents one module of a commercial-scale system, will take 1,000 tons of coal a day, crush it, and mix it with water to form a slurry. The slurry then will be combined with oxygen and ignited to form an intermediate BTU synthetic gas. That syngas then will be cleaned of its pollutants and routed to fuel a conventional combined-cycle power generation system where a gas-turbine generator and a steam-turbine generator will produce a net output of about 100 MW of electricity. The electricity will be fed into the grid of SCE for use by its customers.

The event at Cool Water represents a number of firsts for the industry and for the country. It is the first demonstration of a commercial module of full-scale IGCC technology in the United States. It is the first plant licensed in California to use coal —a potentially dirty fuel—to generate electricity since strict federal and even more stringent state environmental laws limiting emissions from energy sources went into effect. And it is the first demonstration of a synthetic fuel technology that has won financial assistance from the U.S. Synthetic Fuels Corporation (SFC), a quasi-governmental organization formed in 1980 to spur the developing synthetic fuels industry.

The Cool Water project is a $294 million effort sponsored by an impressive array of private energy industry organizations—both foreign and domestic. The sponsoring entities—referred to in program language as participants—and their roles and funding commitments are: SCE, the host utility, operator, and provider of the site, water, and key services for the project—*$25 million*; Texaco, Inc., the developer of the proprietary coal gasification process to be used there—*$45 million*; the Electric Power Research Institute (EPRI), the research arm of the U.S. electric utility industry, which played a key part in establishing the conceptual design of the plant and which conducts continuing technical review and evaluation of the test data—up to *$105 million*; General Electric Company, the developer of the combined cycle technology that will be used in the plant and supplier of the associated equipment—*$30 million*; Bechtel Power Corporation, the prime engineering contractor for the design and construction of the facility—*$30 million*; and the Japan Cool Water Program Partnership, a consortium of Japanese companies led by Tokyo Electric Power Company—*$30 million*. Also participating in the project as a contributor of *$5 million* is the Empire State Electric Energy Research Corporation, an organization of New York state utility companies. In addition, the participants have secured a $24 million loan from two commercial banks to complete the project funding requirements.

The Cool Water program be-

Site preparation and initial construction for the combined cycle generating facility.



Artist rendering of coal gasification-combined cycle plant.

gan in the mid-1970s with conceptual studies prompted by the need among utilities to reduce their dependence on oil and natural gas and to meet ever-tightening environmental regulations. Coal gasification was one of several synthetic fuel technologies under development that would allow utilities to do this. After studies of various coal gasification processes by both EPRI and SCE, the California utility concluded that the Texaco coal gasification process held the most promise for using coal gasification to generate electricity in California.

In early 1978, SCE and EPRI conducted a joint conceptual design study to define the scale and design approach for the project and to obtain a preliminary cost estimate. The cost estimated then was $292 million—within a fraction of what the cost is estimated today. Then, in July of 1979, SCE and Texaco signed the basic Cool Water agreement to establish the objectives, rights, benefits, and obligations of the program. In January 1980, the engineering design phase began with Bechtel chosen as the prime engineering contractor. EPRI joined as a project participant in February 1980, with Bechtel and GE committing funding in September of that same year. In December 1981, actual construction began. The Empire State Electric Energy Research Corporation joined the project in January 1982 and the Japan Cool Water Program Partnership in February of that year, completing funding for the project although, as backers stress, the project is always open for other organizations to join as participants or contributors.

"This Cool Water program partnership arrangement is a unique approach for bringing a new technology into the electric utility marketplace and, in my opinion, one of the most significant steps in bringing synthetic fuels to commercial reality in the U.S.," noted Dwain Spencer, EPRI Vice President for Advanced Power Systems, at the diamond jubilee meeting of the American Institute of Chemical Engineers in October 1983. Spencer stresses that all of the participants in the project are responsible for providing equity, as well as for carrying out a specific technical role in the engineering design, construction, or operation of the project. Because of this arrangement, Spencer notes, "there was a major incentive to control costs and maintain the project schedule."

The program's healthy funding situation was also a strong influence in SFC's July 1983 decision to award financial assistance for operation of the plant in the form of price guarantees—the first such synthetic fuel venture to receive a financial commitment from the government corporation.

"The most important factor in terms of the timing of our awards is the actual readiness of the private sector to commit their own equity to a project," explains SFC Vice President for Projects Ralph Bayrer. "The Cool Water project had been un-

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Dwain Spencer, Electric Power Research Institute Vice President for Advanced Power Systems.

derway for quite some time and had all of its equity committed." Also, explains Bayrer, the project was the most advanced in terms of engineering design work of those it was competing against for SFC assistance. It passed the SFC "maturity" test, and it met the corporation's other criteria as well: its technical risk of scale-up was within reason; it promised to be financially viable; its sponsors had sufficient experience to manage a project of such complexity; there was an adequate market for its output; and there were good prospects for the project to acquire the necessary permits to operate.

Finally, the project sponsors and the SFC were able to negotiate the amount of assistance that the project would need to go forward in the face of a significant market risk. That turned out to be up to $120 million in price guarantees for a period of five years.

"A price guarantee determines what the selling price of a synthetic fuel has to be if the project is going to be financially viable and then we, the corporation, guarantee that price for a certain period of time," explains Bayrer. "If the market selling price is less than the guaranteed price, we make up the difference between the two so that the project can have an adequate revenue stream."

For the Cool Water project, the SFC set a guaranteed price in terms of dollars per million BTUs of gas—since the synthetic fuel being produced at the plant is gas. The market selling price is determined by the value of the electricity produced from the gas. For the first 9 trillion BTUs, the guaranteed price is $12.50 per million BTU, and for the next 11 trillion, it is $9.75 per million BTU.

In order to receive the assistance, the project had to make certain adjustments to its original operating plan. Basically, SCE agreed to operate the plant for an additional 15 years beyond the 5 year demonstration phase if, indeed, the project proves to be economically viable and if the necessary environmental permits are obtained. Bayrer explains why this adjustment was necessary from the SFC standpoint.

"Under the Energy Security Act we are only allowed to support truly commercial production facilities. We obviously have to assure ourselves that the project is truly a commercial plant as opposed to an R&D facility. Originally, the project was only going to be operated for five years, which would not have been a commercial plant. Given our stipulation, the sponsors went back and redesigned the plant somewhat so that it would have a normal commercial timespan."

Construction of the plant is expected to be completed in April of this year with the first production of syngas planned for May. The formal operations phase of the project is anticipated to begin in October.

High Expectations

Expectations are high and enthusiasm strong about the project and the process it will demonstrate.

"I think it's the future replacement for all new coal plants," states Tom Reed, SCE Program Director for Cool Water. "In other words, when new coal plants are built, I think they will be this technology rather than the conventional technology."

"The project fulfills a key niche, if you will, in an overall pattern of diversity that we're trying to achieve for the nation's very large coal resources," explains SFC's Bayrer.

The technology is one of two that EPRI President Floyd Culler told utility chief executive officers in January of this year "hold the most promise for carrying coal into a new age." Along with fluidized bed combustion, IGCC technology is "vital to the future use of coal" and promises to produce electricity "in ways that are not only intrinsically cleaner than conventional coal-burning power systems with scrubbers, but also intrinsically more efficient." EPRI has committed more money to Cool Water than to any other single research project in its program.

The significance of the project and the advantages of the process are numerous. Basically, project backers believe that IGCC technology will allow utilities the flexibility to better face an uncertain future in terms of

Tom O'Shea, Electric Power Research Institute Cool Water Project Manager.

COOL WATER MILESTONES

Early 1977	Preliminary studies commence between Texaco Incorporated and Southern California Edison Company to develop major coal gasification project.
July 1979	Texaco and Southern California Edison sign agreement to build $300-million test facility at Edison's Cool Water Generating Station near Daggett, California.
January 1980	Program moves into second phase: engineering design. Bechtel Power Corporation selected as prime engineering contractor for design and construction of facility.
January 1980	Program Manager appointed. Home Base: Houston, offices of Bechtel.
February 1980	Electric Power Research Institute joins project.
September 1980	Bechtel and General Electric Company join program.
Late 1980	Agreement in principle for Airco Energy Company, Incorporated, to build plant on site to supply oxygen and nitrogen for project.
December 1981	Construction of plant begins.
January 1982	Empire State Electric Energy Research Corp. joins project (as a contributor).
February 1982	Japan Cool Water Program Partnership joins project.
July 1983	Synthetic Fuels Corporation awards Cool Water $120 million in price guarantees.
October 1983	Delivery and erection of the syngas coolers.
April 1984	Construction of plant expected to be completed.
May 1984	First production of syngas expected.
October 1984	Formal operations phase of project expected to begin.
July 1989	Demonstration program completed.
June 1989–May 2004	U.S. Synthetic Fuels Corporation 15 year operations option.

fuel supply, environmental requirements, electricity demand, and the general economic situation.

Most fundamentally, the IGCC technology will give utilities a new way to use coal as an alternative to oil and gas for power production.

"The Cool Water project is very significant if you accept the premise that the utility industry cannot continue to rely heavily on oil and natural gas for power production," notes EPRI Cool Water Project Manager Tom O'Shea. "And I think that is a very valid premise. Everybody knows that oil reserves aren't going to last forever and, even so, the relative instability of sources of supply for oil has become apparent in recent years. If oil were to be relied upon heavily by utilities it would place the industry, and the country as well, in an extremely vulnerable position in terms of continued fuel supply. Here we sit on top of the largest coal reserves in the world by far and so the natural alternative to oil and gas is coal."

These sentiments are echoed by SFC's Baxter. "While this country imports a substantial amount of its energy in liquid form, in terms of solid energy —oil shale, tar sands, and coal —we're probably the richest nation in the world. We have many

Tom Reed, Southern California Edison Program Director for Cool Water.

times the amount of energy in those forms than in all the oil in the Middle East, but it's in the wrong form. And so, for national security purposes, we want to unlock the potential of those solid forms. In doing so, we are trying to achieve some diversity of technology. Coal is our very largest resource base by several times and so it is one of the high priority areas for us to deal with."

The ability to use coal to generate electricity was a major influence in SCE's decision to commit its funding and site to the IGCC technology. At the present time, the utility relies on oil and natural gas for about 60 percent of its power generation.

"Coal is another option in terms of the energy mix," notes SCE's Reed. "It's also a U.S.-based fuel and not subject to the interruptions that oil is subject to. There's quite a supply of it in the West. And it's the most economic way to generate electricity from a fossil standpoint right now."

Recognizing that coal is perhaps the most attractive alternative to oil and gas, the question for the utility industry is how best to use that coal. The conventional method is to burn it in boilers and clean the exhaust gas with scrubbers. This is not, however, the most desirable method from a utility operator's point of view, as EPRI's O'Shea explains.

"Scrubbers are troublesome devices, to say the least. They cost a lot of money to buy and to maintain. They certainly affect the availability of a coal-fired plant because they become a failure and maintenance headache and they produce a considerably large volume of waste material to be disposed of in the form of sludge. In addition, at least in the plants that now operate, they are limited in terms of how far they can go in sulfur removal. So with the disadvantages of coal-firing with scrubbers, it is quite natural that one would look to some other way to use coal."

IGCC systems address the disadvantages of conventional coal-burning with scrubbers in a number of ways. To begin with, the systems offer distinct environmental advantages. The Texaco-based technology to be used at Cool Water promises to demonstrate:

- 95–99 percent sulfur removal
- less than 100 ppm nitrogen oxide emissions
- essentially no particulate emissions
- very inert solid waste.

And not only does the technology inherently allow for such high levels of removal of pollutant material, it does so at lower costs than conventional technology does.

"With the IGCC approach, you have the ability to go to a

The $294 million Cool Water project in California's Mojave desert holds great promise for electric utilities.

The coal, primarily from the Southern Utah Fuel Company, will arrive by rail. It will have a heating value of approximately 11,200 BTU/lb. and a sulfur content of 0.45 percent. Test coals—both high and low sulfur—from other regions of the country will also be run through the plant for short durations during the project.

As rail cars arrive at the site, they will pass over a coal receiving hopper, which is a pit located in a building with flexible doors on the end.

"The building has its own ventilation system and baghouse so the receiving and handling of the coal on site is about as clean an operation as you can make for the nature of coal handling," explains Tom O'Shea, EPRI's Cool Water Project Manager. The coal is then bottom-dumped from the unit cars into the underground hopper situated below the tracks. From there is it transported in a closed conveyer system which looks like a large pipe, up to the top of one of two storage silos, each 6,000 tons in capacity. The silos also have a baghouse on top and a ventilation system for extracting coal dust from the inside.

From the storage silos, the coal is conveyed from the bottom to the top of a coal grinding structure where it passes through two mills: an initial sizing mill grinds the coal to a ¼ inch size and then a rotating wet mill grinds further and mixes it with water. A 60–65 percent coal/water slurry emerges from the grinding mills and is pumped to an intermediate slurry tank. From the tank the slurry is pumped to the top of the 1000-ton-a-day Texaco gasifier vessel, the highest structure in the plant.

It is at this juncture that a major support system for the plant comes into action—the 1,000-ton-a-day oxygen, or air separation plant, that was designed, constructed, and will be owned and operated on the Cool Water site by Airco Inc.

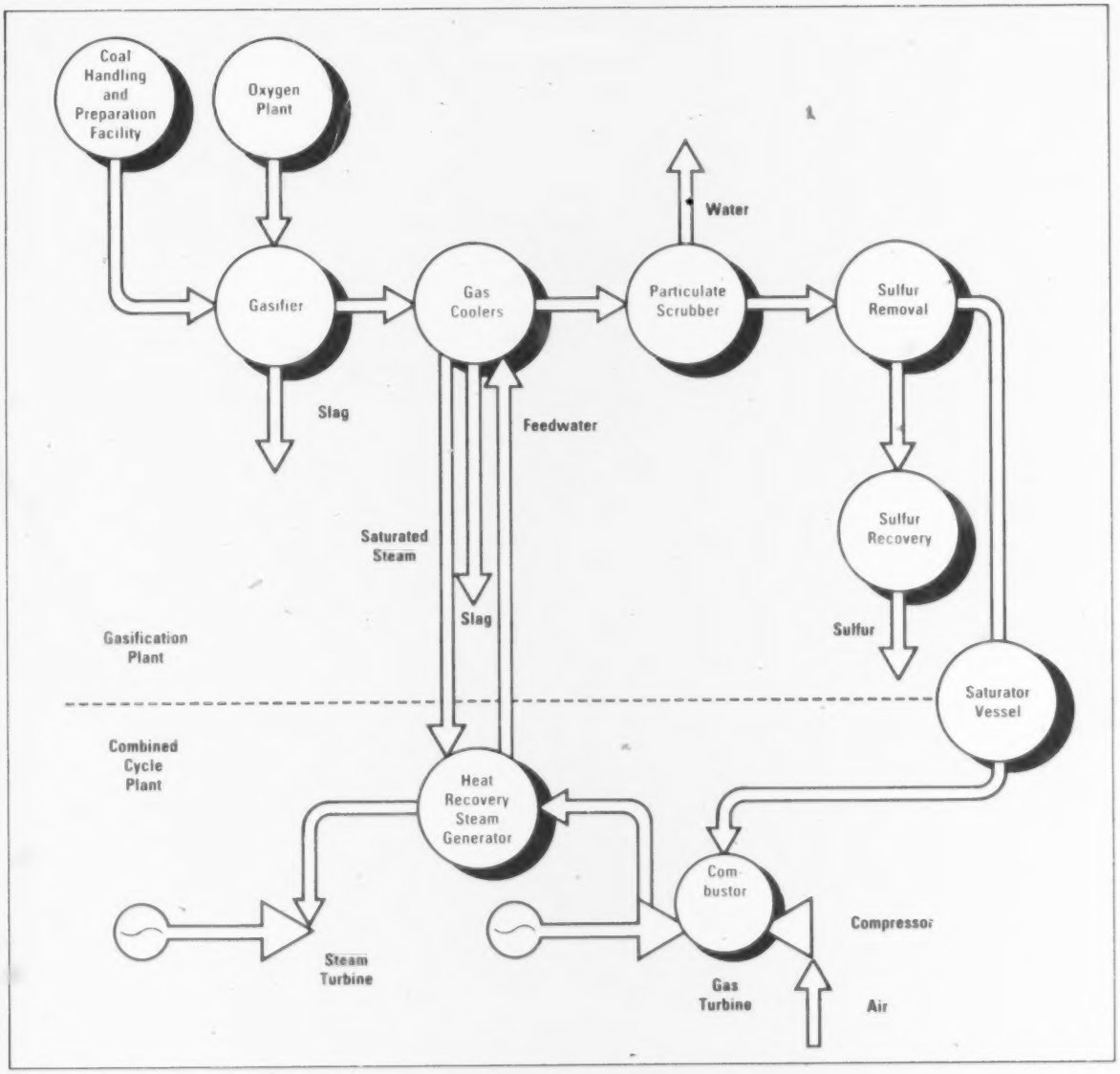
"What the plant does is essentially to distill air at cryogenic temperatures," explains O'Shea. "It converts air to a liquid form at very low temperatures and then separates out its basic components—oxygen, nitrogen, and argon. The oxygen is then vaporized, compressed, and delivered at high pressure to the Cool Water plant."

Approximately equal amounts of 99 percent pure oxygen and the coal/water slurry are fed simultaneously into the gasifier through a specially-designed burner. They react at very high temperatures (2200°F–2800°F) to produce a synthetic gas.

"What actually takes place is a partial combustion reaction," notes O'Shea. The amount of oxygen provided is enough to cause the coal/water slurry to ignite, but not enough to produce full combustion. The carbon in the coal, the oxygen received from the air separation plant, and the oxygen and hydrogen from the water react to produce carbon dioxide, carbon monoxide, and hydrogen. Because of the very high temperatures involved, the ash material in the coal—a basic environmental concern—is melted into a slag of heavy liquid droplets and is carried along with the gas at this stage. The sulfur in the coal is converted almost entirely to hydrogen sulfide.

These reactions occur very rapidly in the gasifier. Residence time there is only a matter of a few seconds. By the time the gas passes out of the bottom of the gasifier, it has two valuable characteristics: a chemical heating value of approximately 260–270 BTUs per cubic foot and "sensible" heat of approximately 2400°–2500°F. The chemical heat is due to the presence of the carbon monoxide and the hydrogen and means that the gas can be further burned as fuel. The sensible heat refers to the high temperature of the gas. "That's heat that can be put to good use," states O'Shea.

And, in fact, it *is* used in the next step of the process, which is the cooling stage. In this step, the syngas is passed through two large syngas coolers, or heat exchangers, which are among the most critical pieces of equipment in the plant. The gas passes first through the large *radiant* cooler and then through the *convection* cooler, each named for the kind of heat transfer that takes place there. In each of the coolers, the syngas passes by tubes filled with boiler feedwater and exchanges its heat with the water in the tubes. In the course of the process, the gas is cooled and the boiler feedwater is heated and evaporated



to make steam, which is used later on in the combined cycle part of the process.

Cooling also serves several other purposes. "First of all the cooling preserves materials in the rest of the plant because at these high temperatures, the gas can be considerably corrosive," states O'Shea. "Secondly, we need to cool the gas down in order to remove the sulfur compounds because the sulfur clean-up process operates at a relatively low temperature." And finally, the cooling aids in removing entrained molten ash material (slag) from the gas. As the gas cools, the slag that it had been carrying as a liquid solidifies once again as mineral matter and separates from the gas. This happens in the radiant cooler. The momentum of the

slag solidifying carries it down to the bottom of the cooler into a water pool where it is solidified further into glassy pellets and removed through a lock hopper system, dumped into a bin, and conveyed to a slag separation facility. The carbon and the water from the slag are recycled for use in the grinding and slurrying stage of the process. At this point, more than 90 percent of the coal ash has been removed from the syngas.

After passing through both the radiant and convection coolers, the gas goes through a carbon or particulate scrubber where it is sprayed with water to wash out any remaining particulate matter that did not come out at the bottom of the radiant cooler. When the gas exits this vertical scrubber vessel, it is essentially clean of particulates. The water used to scrub the gas, along with the particulate matter it has absorbed, is put through a separate processing step that separates out the particulates for recycling back to the slurry preparation system to facilitate the conversion of any remaining carbon. The water is recycled back to the scrubbing process.

When the syngas leaves the carbon scrubber, it is very clean from a particulate standpoint, but it has not yet been chemically cleaned to remove the sulfur compounds—mostly hydrogen sulfide and a small amount of carbonyl sulfide. The temperature at which the sulfur removal process operates is less than 100°F, so it is necessary to still further cool the gas to get it to the temperature necessary for sulfur processing. To do this, the gas goes through a number of small heat exchange steps where its heat is exchanged with other streams in the process. When it has finally been cooled sufficiently, it proceeds to the next step—sulfur removal.

The sulfur removal takes place in what is called an absorber vessel and it involves a commercial physical absorbent process known as the Selexol process, licensed from the Norton Company. The process uses a solvent that is contacted with the gas and, at a particular temperature and pressure, results in the solvent absorbing the sulfur compounds from the gas. When the gas leaves the absorber vessel, 97 percent of the sulfur has been removed. The solvent containing the sulfur compounds is then processed to strip it free of the sulfur and to recirculate it back to the absorber vessel so that it can be used again. The sulfur then is extracted from the resulting acid gas as elemental sulfur in a conventional Claus sulfur recovery plant. Plans call for the elemental sulfur to be sold. The tailgas from the Claus plant is treated further using the Scott process prior to incineration in order to meet California emission control standards.

The syngas, now free of particulate matter and sulfur compounds, undergoes one final step before being routed to the gas turbine for burning. It is passed through what is called a saturator vessel where it is contacted with hot water for two reasons: one, to put some heat back into the gas, and two, to add moisture that will help keep the flame temperature of the gas down during combustion in the gas turbine, thus suppressing the formation of nitrogen oxide.

After the saturator, the gas goes through one more small heating stage to provide a small amount of additional heat to insure there are no materials in the gas that will condense and damage the gas turbine. Then, in fact, the gas does enter the gas turbine. The gas turbine has two sections: an air compression section and the actual turbine combustion section. The syngas is joined with compressed air from the first section, is ignited in the combustion section, burns, and expands. The burning and expanding of the gas turns the turbine blades and drives an electric generator to produce electricity. Exhaust gas from the turbine is at a high temperature —about 1,000°F—and contains a fair amount of sensible heat that can be recovered. This gas is then passed through another heat exchanger—called a heat recovery steam generator—where water in tubes is heated and evaporated to make steam, just as it was in the syngas coolers earlier in the process. At this point, the steam that was produced in the syngas coolers is joined with the steam produced in the heat recovery steam generator and is superheated to a considerably higher temperature. Then all of the superheated steam is routed to a steam turbine to drive a second electric generator and produce additional electricity.

Combined-cycle unit.

considerably higher level of sulfur removal at significantly less incremental cost than can be achieved with a direct coal-fired plant," notes O'Shea. "That's primarily due to the fact that what you're really doing is cleaning a small volume of gas under pressure *before* the combustion air has been added to it as opposed to cleaning the (larger volume of) exhaust gas at atmospheric pressure *after* the gas has been burned in a direct coal-fired boiler." According to O'Shea, the amount of gas to be cleaned in an IGCC plant is less than 1 percent of what would have to be cleaned from the stack of a direct coal-fired plant of similar capacity.

The environmental advantages of the process are key in terms of its use to the industry, notes EPRI's Spencer.

"Clearly, the major value of the IGCC plant to the industry is that it gives the utilities an option for meeting extremely stringent environmental emission control requirements for sulfur emissions, nitrogen oxide emissions, particulate emissions, and solid waste disposal. Furthermore, it should allow the industry to meet essentially *any* level of requirements that might be imposed on them in any future environmental legislation."

This ability to "leapfrog" over ever-tightening environmental requirements is particularly significant in terms of the acid rain issue. Utilities are coming under increasing pressure to curb sulfur oxide and nitrogen oxide emissions from coal-burning power plants because of the charge that these emissions are reacting with components in the air to form acidic gases that come down as rainfall and cause damage to lakes and forests. This issue is growing in terms of both national and international significance and, because of it, utilities may face even more restrictive licensing and environmental control requirements for coal-burning plants. IGCC technology, Spencer stresses, offers utilities the flexibility to meet these requirements in the future.

IGCC systems are also expected to offer utilities increased flexibility in a number of other ways. Basically, the advantage results from the fact that these plants will be modular in nature. Large IGCC plants are expected to consist of a series of parallel modules, according to EPRI's O'Shea. They could include five to six gasifiers, two to four gas turbines, one large steam turbine, two to three sulfur removal systems, and perhaps two or three oxygen plants. This modular nature is expected to aid in increasing the availability of the power plants, O'Shea explains.

"When you have a failure in one of these plants, you don't necessarily lose your entire ca-

. . . a utility could add elements of a plant incrementally, rather than having to commit to the entire plant at once.

pacity as you might in a coal plant. If you have five gasifiers and one gasifier needs to come out of service because it requires some type of repair or replacement, you might only lose 20 percent of your power output, but at least you're able to keep operating and to continue producing power. You don't bring the whole plant down."

The modular nature of the technology also means that capacity could be added in relatively small increments of 250–300 MW with little sacrifice to the cost of power. In addition, a utility could add elements of a plant incrementally, rather than having to commit to the entire plant at once. Such a capability allows a utility the flexibility of tailoring the plant characteristics to meet its needs at a particular time, explains Spencer.

"A utility could first add the gas turbine for peaking purposes and later the heat recovery steam generator to develop a combined cycle capacity by burning either oil or gas. Finally, when it became apparent that fuel prices were such that the utility would not want any longer to use oil or gas, it could add the gasification plant. That flexibility, I think, will end up being a very important attribute from a utility standpoint."

Another advantage of the IGCC plants stemming from their modular nature is that their major vessels and equipment can be shop-fabricated, thus increasing quality control and decreasing lead time.

"Shop fabrication allows for greater quality control because the labor is more highly specialized and skilled and working conditions can be controlled better," notes O'Shea. The major vessels of the Cool Water plant were fabricated in shops and transported to the site for erection. Most critical in this regard were two large syngas coolers. These coolers are heat exchangers that cool the syngas after it has left the gasification vessel in order to prepare it for sulfur removal, to produce steam to be used later in the process, and to aid in returning most of the mineral matter in the coal back to a solid form for easy disposal. The coolers—each 600 tons, 15 feet in diameter and 120 feet long—were fabricated by Combustion Engineering at its Chattanooga plant and then transported via barge by way of the Tennessee and Mississippi Rivers, the Gulf of Mexico, the Panama Canal, and the Pacific Ocean to Long Beach, California. From there each vessel, one at a time, was transported by a special Schnabel rail car (350 feet long, 36 axles, over 1,000 tons gross) to the plant site at Daggett. The total journey covered 9,000 miles.

"That was quite a circuitous route," states O'Shea, "but it was solely for the purpose of maintaining the complete fabrication of those vessels in the shop where quality control would be at its best."

Shop fabrication also contributes to decreased lead times for design and construction of the plant. Project sponsors expect to demonstrate at Cool Water that IGCC units would require a lead time of only three to four years from the time that a utility commits to the detailed engineering to the time that the plant actually goes on line. Construction time at Cool Water itself was only about 28 months.

This short lead time advantage is very important in the context of the industry's need to be able to match capacity additions with load growth, notes Spencer. And it is particularly important in today's U.S. electric utility market where load growth is low and uncertain and raising capital for 1000 MW power plants is difficult and costly.

Objectives

With so many distinct advantages, do the project backers feel that there are any disadvantages for the IGCC process to surmount? The only one cited relates to the complexity of the system and its newness to the industry.

"The major disadvantage is that we are adding a major chemical processing step onto the front end of the combustion process and, therefore, there is a degree of unfamiliarity on the part of the industry in being able to operate the process units," explains Spencer. The Cool Water project is designed to overcome this one disadvantage by giving the industry some experience with this new kind of plant.

"We are going to be operating in a totally integrated fashion to determine the degree of complexity that this front end processing plant adds to the overall plant operation," he continues.

... post-Cool Water plants might come on line as early as 1990 or 1991.

"Hopefully, we'll demonstrate that there is a satisfactory availability in the performance of that front end so that the industry will be comfortable with it."

What other objectives does the project hope to meet? A key one is to determine the performance of the system from an efficiency standpoint and to verify previous performance estimates. The overall heat rate for Cool Water is expected to be approximately 10,800 BTU/KWh, which means a coal-to-busbar efficiency of 32 percent. EPRI studies show that higher efficiencies could be achieved, perhaps 36–38 percent in a commercial plant using larger, more efficient steam turbines and incorporating other variations in the process. A normal, modern conventional coal-fired plant has an efficiency of 33–36 percent.

The project is also intended to confirm the environmental performance of the process, to verify that the emissions and other effluents from the plant are what they have been designed and are estimated to be.

Another objective is to confirm that the process operates well from an environmental and maintenance standpoint on a wide range of U.S. coals, including both high- and low-sulfur coals. Also, project participants will be evaluating the overall controllability of the system and its flexibility in responding to various utility operating modes —start up, shut down, load following, and emergency operations. They also will be thoroughly assessing the reliability, maintainability, and overall availability of the system and its various parts.

"We'll be carefully monitoring equipment failures, frequency of those failures, the time it takes to repair them and possible alternative designs or materials that would reduce the frequency of failure to develop an acceptable overall capacity factor, or availability, for the system," notes O'Shea.

A final objective is to evaluate the costs of the system. EPRI has conducted numerous engineering and economic evaluations which indicate that mature commercial IGCC plants should produce busbar power at costs of approximately 5 cents per KWh (in 1983 dollars) from a range of emerging coal gasification technologies, with particular emphasis on the Texaco system. Analyses indicate that the minimum size of IGCC powerplants to be economically competitive would be in the 250–300 MW range, most probably based on three parallel 1,000 ton/day gasification-gas cooling systems, a single sulfur removal train, two combustion turbines, and a single reheat steam turbine.

Beyond Cool Water

If the Cool Water project meets its objectives—and backers obviously believe that it will—when could a utility expect to order an IGCC plant and how widespread might these systems be?

According to EPRI's O'Shea, a utility might begin to commit to an IGCC system as early as 1986 after Cool Water has operated for a few years and its degree of success has been determined. That would mean that post-Cool Water plants might come on line as early as 1990 or 1991. As for the possible widespread nature of the systems, project backers say it is too early to speculate, but they point to the newly formed Utility Coal Gasification Association with 29 utility members as an encouraging measure of utility interest. The purpose of the association is to assess the potential of various coal gasification technologies, to review economic and performance projections for the systems and to serve as a focal point for potential suppliers of coal gasification technology.

"So although it is premature to measure the success of Cool Water or its ultimate impact on the electric utility industry, it is clearly providing the basis for a realistic appraisal of this promising new method of using coal," Spencer states. If Cool Water does what he and others involved in the project expect, it will provide utilities with an option for a new kind of power plant to use coal in the 1990s and into the new century—one that will do so cleanly, economically, and reliably.

THE ALICIA STORY

Houston Lighting & Power Company weathers one of the most devastating hurricanes ever.

By Mark R. Reynolds

Mark Reynolds is a Washington, D.C., based freelance writer.

On August 18, 1983, hurricane Alicia tore through southern Texas. Generating winds of up to 135 mph, Alicia came ashore from the Gulf of Mexico near Galveston, moved straight through downtown Houston, and followed a northwesterly course that covered almost the entire area served by Houston Lighting & Power Company (HL&P). The storm caused the greatest and most widespread destruction to HL&P's system in its 102-year history. Approximately 750,000 customers lost electric service—more than the total number of HL&P's customers when hurricane Carla struck in 1961.

In spite of Alicia's devastation, HL&P restored service to all customers in only 16 days; over 80 percent of affected customers had their service restored within 4 days. This amazing record is the result of HL&P's carefully developed and effectively implemented Emergency Operation Plan, a case study of the way in which the electric utility industry strives to anticipate the many challenges confronting it to minimize their adverse effects on its customers.

The following report chronicles the company's response to hurricane Alicia from the early stages of preparation before the storm struck through the complicated recovery process.

Monday, August 15

Alicia, the first tropical storm to be named during the 1983 Atlantic hurricane season, appears in the north-central Gulf of Mexico. Located more than 350 miles east of Corpus Christi and with winds of only 40 mph, the storm drifts toward the west, as forecasters warn conditions favor its strengthening.

In response to these warnings, HL&P activates its Emergency Operation Plan, a blueprint for restoring service developed over many years of experience in coping with hurricanes, ice storms, and other emergency situations.

The plan designates procedures for all departments before, during, and after storms. Personnel know where to report and what their duties will be well in advance of the actual storm. The plan even details operations down to the last vehicle: vitally needed trucks receive maintenance so they are not out of service because of bad tires or faulty ignition systems. Because negotiating with contractors takes up precious time during an emergency, the plan calls for pre-negotiations for pricing and other arrangements.

At the first storm alert, preliminary hurricane preparations begin at all power plants. HL&P determines what equipment needs to be tied down, checks stocks of supplies for operating the generating units, and secures the food and bedding required for personnel who might remain at the plants for an extended period of time.

Tuesday, August 16

What had been a listless tropical storm turns into a major hurri-

Wide World Photos

Beach homes on Galveston Island destroyed by Hurricane Alicia.

Wide World Photos

Galveston Marriott feels Alicia's 135 mph winds.

cane. At 11 p.m., the National Weather Service (NWS) reports Alicia packing 80 mph winds and located about 140 miles southeast of Galveston. There is nearly a 50 percent chance that it will come ashore at Galveston.

Wednesday, August 17

Alicia stalls in the Gulf, but continues to grow larger and more dangerous. The NWS predicts the storm will move inland between Freeport and Galveston before dawn Thursday, but its erratic and aimless movements throughout the day Wednesday defy accurate prediction. "It's kind of like a gorilla with a machine gun. It goes where it wants to," remarks a Houston meteorologist.

With the formal storm alert on Wednesday, HL&P makes final preparations by following a checklist for each plant's emergency plan. Employees are told to be prepared to come early to prevent any shortage of trained personnel and to be prepared to stay as long as necessary. Exact work schedules vary from plant to plant, depending on their location, and are established by the close monitoring of ocean tides. At the P. H. Robinson plant, which can be isolated by a five-foot high tide in Galveston Bay, for example, storm workers report at 12:30 p.m. Wednesday. At the Cedar Bayou plant, which would not be isolated until tides reached 10 feet on Trinity Bay, additional employees are brought in late Wednesday evening.

The planning pays off: during Alicia it is impossible to get people into the Robinson, Cedar Bayou, or Deepwater plants for approximately eight hours.

Physical preparations involve tying down everything in the plants that could be blown into switch yards or lines. Glass is taped or boarded, and ropes are run through walkways so operators and maintenance people can hang on while walking through open plant areas during the storm.

Looking after the welfare of critical customers—persons who depend on life-sustaining machines—is another area of serious concern. As Alicia approaches the service area, Field Activities and Customer Service personnel contact each of the 263 people on the company's critical customer list to verify their situations and the number of hours each can go without a life-sustaining machine. Field Activities also checks on the

Wide World Photos

Boat owners inspect damage at Bal Harbor in the Galveston Bay area.

HL&P's Emergency Evaluation Center for gathering and dissemination of information on system operation and restoration activities.

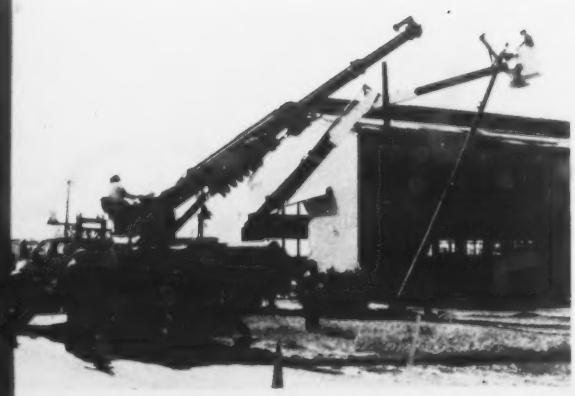
availability of generators for critical customers, and contacts rental firms to line-up equipment since company-owned generators will be required immediately after the storm to provide emergency power for HL&P facilities.

Preparations to activate the company's Emergency Evaluation Center begin well before Alicia's arrival. Operated by the System Engineering Department, the center provides a centralized point for gathering and disseminating information on system operation and field restoration activities. Each year by the start of the hurricane season, the 13th floor conference room in HL&P's downtown Houston headquarters building is equipped with system wall maps, an eight-channel radio, one regular telephone, and six pick-up telephones. As part of the company's overall Emergency Operation Plan, one pick-up telephone line goes to the system dispatcher, one to the Transmission Construction office, and one to each of HL&P's four zone headquarters.

Late Wednesday, System Engineering takes final steps to activate the Emergency Evaluation Center by gathering copies of smaller service area maps, essential telephone numbers, engineering personnel rosters, and other supplies needed for a 24-hour operation.

The nerve center of HL&P's electric system is the Energy Control Center (ECC), located near downtown Houston. The ECC utilizes computer systems operated by highly-trained dispatchers to route the flow of power throughout the company's network of electric lines. Some ECC personnel are sent home early Wednesday so they can return to the center late that night. Communication links between the ECC and the Emergency Evaluation Center are established and the Customer Service Department calls in additional staff for the critical Telephone Service group. All Telephone Service representatives are advised to be prepared to spend the night, and late Wednesday employees pitch cots wherever they can find a quiet

Approximately three-quarters of a million customers are without power.



Alicia downed more than 2,300 transmission poles.

-place and try to get what little sleep they can before the storm hits.

Thursday, August 18

The slow-moving Alicia finally makes up its mind and comes ashore about 3 a.m. at San Luis Pass. With winds of up to 135 mph, Alicia proceeds northward on a path of destruction.

The devastation to HL&P's system is ruthless. Approximately three-quarters of a million customers are without power. Fifty transmission circuits are unusable, and 70 HL&P and customer-owned substations are out of service. Of the 1,100 distribution circuits that carry electricity from the substations, 569 lock out. Alicia knocks 6,928 spans of wire and 2,358 poles to the ground. More than 40,000 service drops (attachments between distribution poles and customer buildings) are torn loose. Three high-voltage transmission towers topple, and all four transmission lines to Galveston go out, leaving the entire island in darkness. Finally, 6,213 line fuses blow, and 2,710 transformers are destroyed by the storm.

No one sees the storm's destructive power more graphically than dispatchers at HL&P's ECC. As Alicia's winds fell power lines, knock out major distribution substations, and damage power plants, ECC dispatchers track each event on large electronic maps and computer displays. As reports continue to come in, they describe enormous damage to the entire HL&P transmission and distribution system.

The power generation needs of the 5,000-square-mile area served by HL&P plunge unbelievably—from a high of over 8 million kilowatts at noon Wednesday to an almost 20-year low of 1.3 million kilowatts at noon Thursday. Dispatchers know that the dramatic drop during the storm will be followed by a strong demand for power as field crews begin repairing lines. For this reason, there is particular concern that setting generating stations back to a low level of output will endanger the system's ability to return quickly to a higher level.

Dispatchers, working through the Electric Reliability Council of Texas (ERCOT), make arrangements with other utilities to export power from the HL&P area during the period of lowest electrical demand—exactly the reverse of most emergency situations when power needs to be imported to a troubled area. (The strategy will pay off when demand rebounds strongly to over 6 million kilowatts by noon Friday.)

Customers never know that throughout the day on Thursday HL&P dispatchers walk a narrow tightrope, balancing electricity supply and demand to avoid supply complications.

"From early in the morning until late in the afternoon, the storm wallowed over the Houston area and gave us a beating. It wasn't until late in the afternoon when the winds died down that we could begin to evaluate the destruction. Still, we knew we needed to keep the system stable. We didn't want to overload tie lines, but we needed to keep the nucleus of the system operating. By exporting power we were able to do just that, and we owe a lot of thanks to other members of the interconnect who helped us out. The possibilities were there for very serious damage to the system, and during the heaviest part of the storm, all of us at the Center were extremely tense. But everyone pitched in and was willing to do whatever was necessary. These are dedicated and experienced professionals—they were thinking ahead."
Ralph Abshire, HL&P Manager of Energy Control and Dispatching

An electric system modeling computer speeds dispatchers in

HL&P put 1,697 qualified line repair workers in the field.

restoring power to substations. HL&P engineers originally developed the system to depict the area's electric supply system and predict the electrical effects of adding new customers in specific locations. With major transmission lines knocked out of service, engineers and dispatchers use the modeling computer to test alternate power-delivery routes along remaining lines. This technique avoids the potential problem of overloading circuits.

Critical facilities, like hospitals, water wells, and sewage-treatment plants, are back in operation first, followed by municipal necessities such as police and fire stations. HL&P crews then concentrate on restoring major transmission circuits. By Thursday night, half the transmission circuits reported out are back in operation. As these circuits are reenergized, crews begin the difficult task of repairing the distribution system from the substations to customers' homes and businesses. The approach is to commit resources to those locations where the most customers can be restored as quickly as possible.

By the end of the day Thursday, HL&P restores service to some 420,000 customers.

"The major part of our force worked 14-hour shifts throughout the restoration period, and they all performed yeomen's service in getting our system back together. Hundreds of crews were working all over the area, but with all the problems from Alicia, the restoration wasn't easy. The public doesn't always understand this. A man sees his neighbor's lights on and wants his own electricity restored as well. There are always complaints; it's human nature. But our people did an incredible job."

Glenn Cole, HL&P General Manager of Distribution and Service Center Operations

Water-system service poses a critical problem during the early hours of August 18. Nearly all 126 electrical connections to Houston's water service are either out or inoperative, and water pressure in the downtown area falls to less than 7 pounds from a normal pressure of 60–65 pounds. The underground water storage supply at the Central Water Control Center is depleted in approximately five hours, and above ground reservoirs at the Heights and Staples stations are emptied by nightfall. The South End-pumping station serving the Houston Medical Center is out of service, along with most of its supplying wells.

HL&P crews move out in the midst of high winds and heavy rains to make emergency repairs to power lines serving the three principal downtown water reservoirs and pumping stations. They direct their primary efforts at restoring power to the Central station because it controls the flow of water in mains throughout the city. HL&P crews successfully reenergize this crucial water facility at about 10:30 a.m., in spite of adverse working conditions. Heights and Staples stations are back in service by late Thursday afternoon. By early Friday morning, the first day following the storm, enough wells are energized to provide minimum water supply to downtown Houston.

Friday, August 19

To cope with Alicia's destruction, HL&P assembles what is probably the largest restoration force ever mobilized to repair an electric system. The company puts 1,697 employees qualified for line work into the field. Street lighting and meter reader personnel are pressed into ser-

Wide World Photos

To cope with Alicia's destruction, HL&P assembled probably the largest restoration force ever mobilized to repair an electric system.

vice to re-fuse distribution lines and repair downed lines. Locally contracted crews, consisting of 353 qualified workers, report for duty on Friday. An additional 709 people skilled in electrical repair work are brought in from investor-owned and municipal electric utilities. Fallen trees and broken limbs must be removed before equipment can be replaced or repaired. HL&P uses 250 tree-trimming crews, including 85 borrowed from municipalities and other Texas electric utilities, to carry out this priority work.

Crews face repair problems that vary from routine to extremely challenging. Poles or transformers beside streets are replaced without too much difficulty within an hour or so. However, Alicia also knocked down poles and lines in backyards and many other difficult locations, including a bayou with houses and debris blocking access. In places inaccessible to trucks and power tools, men set poles 50 to 75 feet long by hand and lift transformers weighing more than a ton by block and tackle.

"In our area, there were about 30,000 customers without electricity after the storm. We were out in the field while the storm was still going on trying to keep main circuits open. The winds were pretty strong; I'd say 55–60 mph. We followed standard procedures, though there were times when you got a little scared being out in that wind. But we kept a lookout for one another and used our heads. The guys in this business have a real feeling for the community. The more they could do, the happier they were. Everyone fell in and worked—14 hours a day, seven days a week. It was hard going. My own electricity was out for seven days. I'd get home needing a hot bath, and there was no hot water. It was quite a chore"

O. R. Johnson, Head Linesman, HL&P Tomball Service Center

Saturday, August 20–Monday, August 22

During the critical days of service restoration, the Emergency Evaluation Center operates around the clock. System engineers perform studies to establish temporary reconnection of transmission facilities and issue operating procedures and relay settings so the Transmission and Distribution Department can accomplish the needed repairs on the most timely basis. The studies consider the best way,

not necessarily the easiest way, to make repairs so additional problems will not be created elsewhere on the system.

"For a lot of people working at the Emergency Evaluation Center, this was the first serious emergency of any kind that they had experienced. Practicing to cope with emergencies and actually facing an emergency are not the same thing. However, everyone was really up, and they performed even better than I had anticipated. Their attitude was unbelievable. There were no complaints about the long hours, even though a number of people on our staff had suffered damage to their own homes and couldn't leave to check on them. I think that the majority of people in our business feel a real responsibility to serve, much more so than in other industries. Our people were willing to do much more than we could ever have demanded that they do."

Jack Greenwade, HL&P Vice President of Engineering

One of the most important jobs of the Evaluation Center is determining on which dates customers can expect power to be restored. This is a critical element in meeting the needs of the public. Maps show each Transmission and Distribution foreman's best estimate of the time necessary to restore service in his assigned area. A copy of each map is supplied to Customer Service and the date entered into a computer so that each telephone representative can bring the information up on his or her screen. Updates are made on a daily basis.

All Customer Service employees work 12- to 14-hour shifts at normal or temporary work locations since Telephone Service, which always operates 24 hours a day, seven days a week, suddenly has to handle a much heavier volume of calls around the clock.

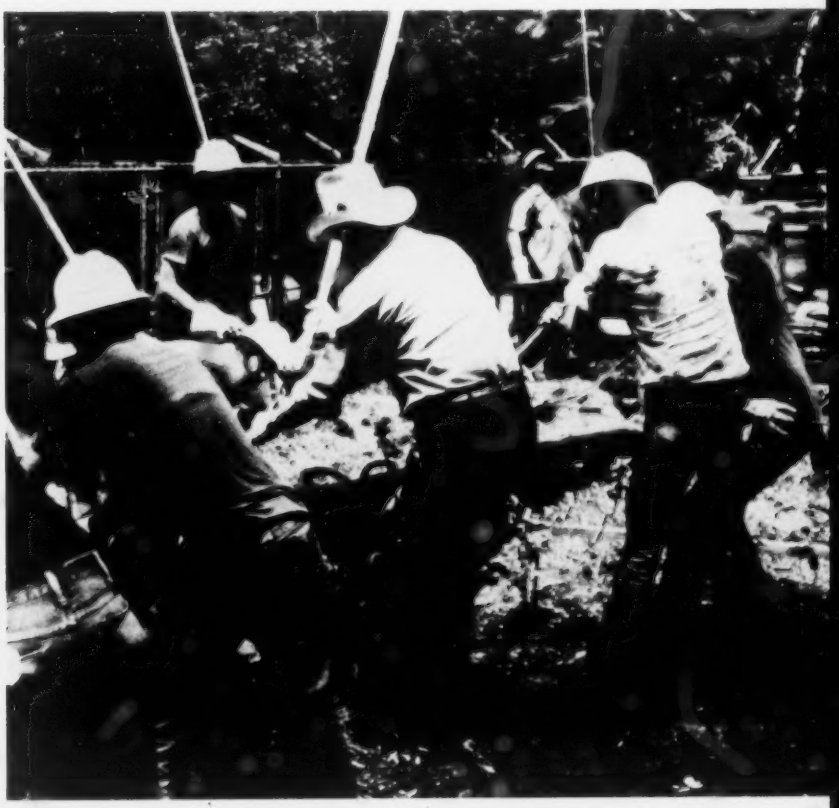
The 414 Telephone Service Division employees, with assistance from over 450 additional personnel, answer 510,400 customer calls in the 11 days from Thursday, August 18, through Sunday, August 28. On Saturday, August 20, the division handles over 66,400 calls. (During a *normal* busy weekday, customers make fewer than 20,000 calls, and weekends average fewer than 3,000 calls per day.)

"The hardest job Customer Service had was to provide the most reliable information to customers about when their service would be back on. It was a complicated problem. The initial survey of damage was bad, but the second survey was even worse. If you tell a customer that he'll have service in two days and then something happens and he doesn't get it, he calls back two days later madder than before. It's frustrating for the customer and for the telephone service person who's dealing with customers.

"But I would put the staff in our office up against any staff in the country. They did an incredible job. When the water supply system went, we had no water, no air conditioning, no toilet facilities. Imagine 300 people on the phones working in 93 degree temperatures with nothing

Probably no other electric system in the country has incurred more damage.

Workers completed all repair work in only 16 days.



to drink and no way to go to the bathroom. At best it was tacky, at worst horrendous. But the morale was tremendous, and there was an incredible sense of achievement about attacking a problem and solving it.

"We also learned a lot as a result of Alicia. Interfacing with other departments gave the staff a much clearer sense of the company and its operations, and being very much at the center of emergency operations gave all of us a renewed appreciation of our importance within a team effort. Amazingly enough, after the emergency had passed, our office experienced a minor depression. After such a high, it was somewhat hard to go back to business as usual."

Bill Caughran, HL&P Manager of Customer Service

Customer Service gives continued priority attention to the needs of the company's critical customers. As company-owned generators become available, they are delivered to critical customers who are without power. While company generators are tied up in the restoration effort, critical customers are provided generators from rental firms. When, for example, a young boy on a respirator is due home from the hospital, a Field Activities representative locates a generator at a rental agency only to discover that the boy's family does not have the necessary $150 cash deposit. The HL&P representative secures the deposit with his personal credit card, which the rental agency agrees to accept providing the company be responsible.

A problem faced by many critical customers with generators is the unavailability of gasoline. Field Activities personnel also come to the rescue by locating service stations with operating pumps, obtaining gasoline, and delivering it to critical customers who have generators but are unable to find gasoline. This service continues through Saturday, August 20.

Maintaining the flow of information to customers and federal, state, and city officials is a major company responsibility. HL&P provides daily updates of restoration progress to the Public Utility Commission of Texas

Through October 31, the cost to HL&P from Alicia totals $27 million.

and the mayor of Houston. Company officials contact the Department of Energy's Office of Energy Emergency Operations in Washington to apprise them of the status of HL&P's system. Public Affairs personnel work around the clock making sure that critical information is made available to news media as it comes in at the company's Emergency Evaluation Center.

Besides providing damage and repair updates throughout the days and nights during and after the storm, Public Affairs works to make sure that particularly important messages get priority. All news media, particularly radio stations, give excellent cooperation in relaying current information to customers. For example, radio stations publicize the serious safety concern for linemen and customers from portable generators. If these machines are wired directly into a home's electric system, current can flow back through the HL&P wires, with transformers boosting the voltage to dangerous levels. Effective communication warns customers of this and other potential hazards.

News media interviews with work crews and company officials help quell rumors, answer questions, and even report frauds. As tree-trimming crews work through a neighborhood, a man goes ahead of them seeking to collect a fee for their services. With news media help, customers are quickly advised that the company is seeking no fees and that the police should be notified if someone does seek to collect for HL&P tree trimming work.

Over 500 calls come in from news media outlets seeking information, some from as far away as England. The department issues 39 storm damage and restoration progress reports during storm repair efforts.

With so much equipment to repair or replace, equipment purchases are a critical element in the recovery from Alicia. In anticipation of the hurricane, HL&P had begun to purchase equipment and supplies two days before the hurricane arrived, and storm-related purchases would continue for 12 days after the storm. During this period, HL&P places 1,323 emergency orders for equipment, supplies, and services. These orders include 3,000 distribution poles, 4,000 wooden cross arms, 4,500 pole-type transformers, 5.6 million feet of wire, 26,158 insulators, 10,000 meter sockets, 5,000 flashlights, and 80,000 flashlight batteries.

To meet the demand for large amounts of cash, major Houston banks supply HL&P with money as it is needed. The company borrows in excess of $200,000 and is allowed to draw funds over the amount in its account. Calls to banks provide funds in 20 to 30 minutes, while three cash tellers from the company's Treasury Department handle some $250,000 in cash for service centers without a single error.

Through October 31, the cost to HL&P from Alicia totals $27 million.

Friday, September 2

HL&P restores service to those final customers still without power.

Alicia represents the latest and greatest of the many challenges electric utility companies, and their employees have overcome in more than 100 years of providing reliable electric service. Until Alicia, hurricane Carla in 1961 had been the yardstick by which HL&P had measured tropical storms. But that is no longer the case. Probably no other electric system in the country has incurred more damage than did HL&P as a result of Alicia. But through the untiring efforts of the men and women of Houston Lighting and Power Company, a restoration effort unparalleled in the company's history was accomplished in only 16 days.

POWER PLACES

Photography by John Pfahl

John Pfahl began photographing the American landscape nearly a decade ago with the intention of dealing exclusively with the issues of beauty and the picturesque. Several years later, Pfahl recalls, he started to include in his photographs objects that he previously had traveled great distances to avoid.

"I found that power installations had the habit of settling in some of the most picturesque corners of the landscape and that I was forced to deal with that issue," Pfahl explains.

In later research, he found that the 19th century painters of American landscapes (the Hudson River School, for example) actually had developed a sub-category of landscapes in which they included the new industrial sites beginning to dot the natural environment.

"I am fascinated by the engineering of the installations themselves," Pfahl explains, "by their sheer monumentality, and by the way they react with the natural landscape pictorially."

As a recent issue of *American Photographer* describes it: "Power plants . . . commonly understood to be intrusions in the natural landscape, are simply integral parts of Pfahl's photographic landscapes. We may think of them as aberrant, but in Pfahl's carefully elaborated scheme of things, they belong.

"The seamless magic of Pfahl's imagery is such that we see his problematical 'power places' with the unjudgmental wonder of a visitor from another world, viewing this curious planet long after mankind's mischievous career has ended."

Pfahl is currently a Visiting Professor of Photographic Arts at the University of New Mexico in Albuquerque, having held similar positions at other institutions. His more than 25 solo exhibitions, most recently *Power Places* at the Freidus/Ordover Gallery in New York City, are part of an impressive list of worldwide showings, which also includes more than 20 group exhibitions and a like number of inclusions in permanent public collections.

Windmill, Boone County, North Carolina

Clockwise from bottom left: Pacific Gas & Electric Plant, Morro Bay, California. Solar One Plant, Barstow, California. Four Corners Power Plant, Farmington, New Mexico

Ginna Nuclear Plant, Lake Ontario, New York

Diablo Dam, Skagit River, Washington

Rancho Seco Nuclear Plant, Sacramento, California.

WHAT HAPPENED TO THE 40 PERCENT?

This article is based on a report provided by the independent economic consulting firm Data Resources, Incorporated, to Edison Electric Institute's Energy Modeling and Research Department.

Growth in electricity demand in the United States diminished considerably between 1972 and 1982. Had it continued to advance at the average annual rate established between 1960 and 1972, by 1982 electricity consumption would have been 40 percent greater than it actually was. This analysis compares demand growth for the two periods and explains the difference in the 1970s in terms of several underlying variables.

The 1970s were tumultuous for energy. The sharp break in the performance of the economy from the preceeding years was startling as well. Table 1 shows the dramatic difference in growth rates of various economic and energy-use indicators before and after the Arab oil embargo of 1973–74.

From 1973 to 1982, growth in the GNP and real disposable income averaged less than half of what it did before the embargo, and inflation more than doubled its previous 12-year growth rate. But changes in economic growth were not the only factors contributing to the post-embargo reduction in electricity demand. Alterations in the sectoral composition, or mix, of electricity demand accentuated the effect of slower overall economic growth. Purchases by the industrial sector, where usage rates are highest, grew more slowly than purchases by the residential and commercial sectors for both time periods. Finally, the rise in electricity and other energy prices after 1973 spurred conservation and reduced demand in all three sectors. For example, the efficiency of electric appliances, which had declined during the pre-embargo period, reversed to show a 1.8 percent average annual gain following 1972, thus reducing electricity demand. However, the impact of price-induced reductions in demand was offset somewhat by the sharp drop in the price of electricity relative to other energy prices.

Table 1

Economic and Energy Use Indicators Average Annual Percentage Change

	1960–1972	1973–1982
Economic Growth		
Real GNP	4.0	1.9
Real disposable income per capita	3.0	1.3
Price Changes		
Electricity Price (nominal)	−0.6	11.7
Inflation	3.2	7.7
Population	1.3	1.0
Labor Force	1.9	2.3
Electricity Consumption		
Total U.S.	7.0	2.0
By Sector		
Industrial	5.3	1.3
Commercial	10.0	2.9
Residential	8.3	3.1
Energy Efficiency Improvements in New Household Electric Appliances (reduction in electricity required per unit of time)	−1.2	1.8

Figure 1 illustrates the quantitative effects of all three factors on electricity demand. The lowest line indicates total actual demand, which in 1982 was 2,094 billion kilowatt-hours (KWh). The broken line shows what electricity demand would have been had it continued to grow at its historical trend. The gap between these two lines shows the incremental effects of slower economic growth, the changing sectoral mix, and higher electricity prices. (Note: While the trend line is merely actual 1972 demand smoothly expanded by the 1960–1972 growth rate, the impacts of the individual economic factors, discussed here and throughout this report, are computed by regression analysis. Consequently, the difference between trend demand and actual demand does not translate exactly to the sum of the impact of the individual factors because they are figured independently.)

The slowdown in economic growth was by far the most significant factor leading to slower growth in electricity demand. If the economy had maintained its trend growth rate, total electricity demand would have been 24 percent higher than actually realized. Mix changes were the least significant factor, contributing less than 5 percent to the reduction in electricity purchases.

Two hypothetical price-related occurences are also illustrated in Figure 1. First, the solid line within the price bracket shows that if both the price of electricity and its position relative to other energy forms re-

Figure 1

Total United States Trend Versus Actual Electricity Demand Growth

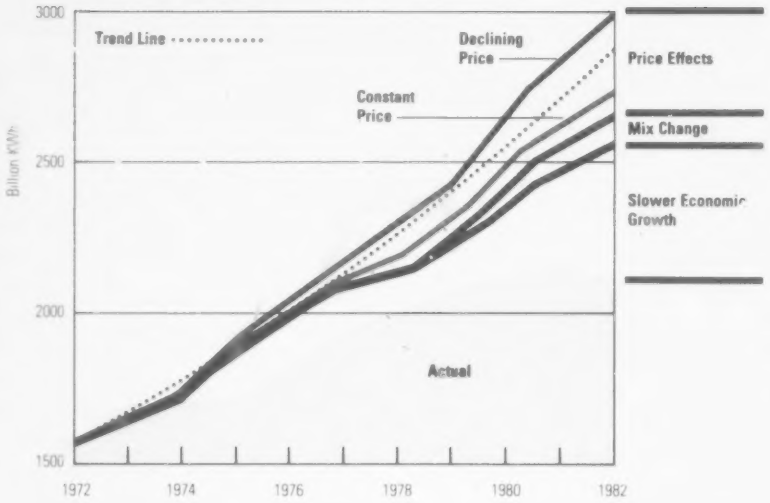
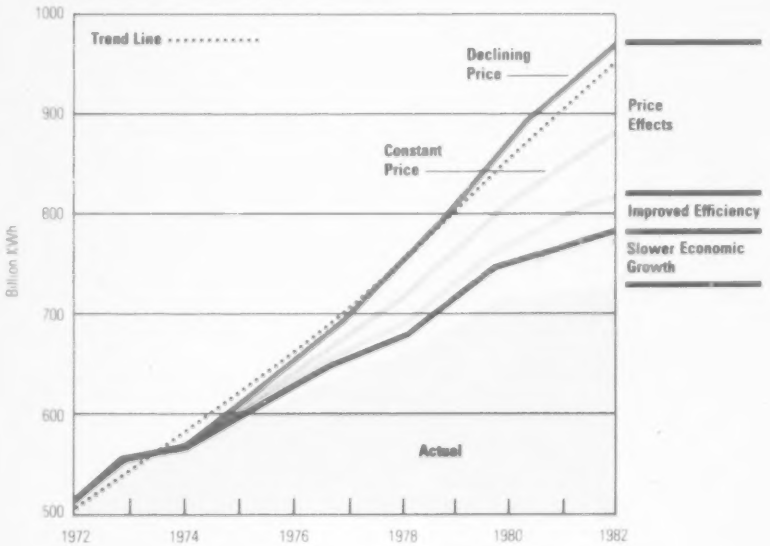


Figure 2

Residential Electricity Demand



mained constant at 1972 levels, electricity purchases would have been just 3 percent higher than they actually were. Second, the top line of the price bracket shows that if actual and relative electricity prices had continued to decline along their downward trend of the historical period, actual demand would have increased 15 percent, or 314 billion KWh.

The Residential Sector

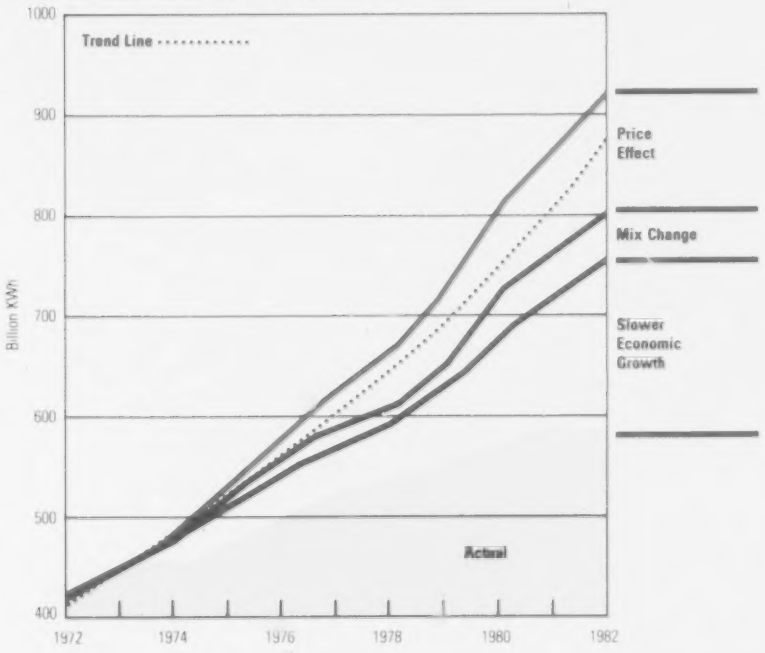
The trend projection for residential electricity demand in 1982 was 957 billion KWh, 30.6 percent above the actual figure. Price effects had the largest influence on reduction in demand for this sector, shown in Figure 2. Had the price of electricity remained constant at 1972 levels in absolute terms and relative to that of other energy forms, residential demand would have been 8.1 percent higher. Had the price and its relative position declined at trend rates, demand would have increased 20.1 percent more than it actually did.

Price-induced improvements in the efficiency of appliances also had a depressing effect on residential demand. Prior to the oil embargo, consumers placed little emphasis on the efficiency of household appliances. But price hikes in all energy forms following the embargo increased attention to appliance efficiency, and, as technological improvements increased appliance efficiency, residential demand declined 4 percent.

Finally, slower economic growth, experienced in the residential sector as the result of slower growth in disposable real income, which led to slower growth in housing formation, depressed actual electricity consumption 7.8 percent from what otherwise would have been consumed.

Figure 3

Commercial Electricity Demand



The Commercial Sector

Had commercial electricity demand grown at pre-embargo rates, 1982 consumption would have been 882 billion KWh, or 50.5 percent above the preliminary actual figure available for this analysis. As shown in Figure 3, the effect of slower economic growth, measured by commercial output and real disposable income, was huge, accounting for a 30.5 percent reduction in actual demand. In addition, between 1972 and 1982, the commercial sector underwent a slight shift away from more electric-intensive subsectors to less electric-intensive ones. This mix change reduced commercial demand 8 percent. Finally, if real energy prices had held at their 1972 levels, the impact of conservation and of fuel substitution would have closely offset each other. However, if actual and relative electricity prices had maintained their historical

decline, actual electricity consumption would have increased 20.4 percent.

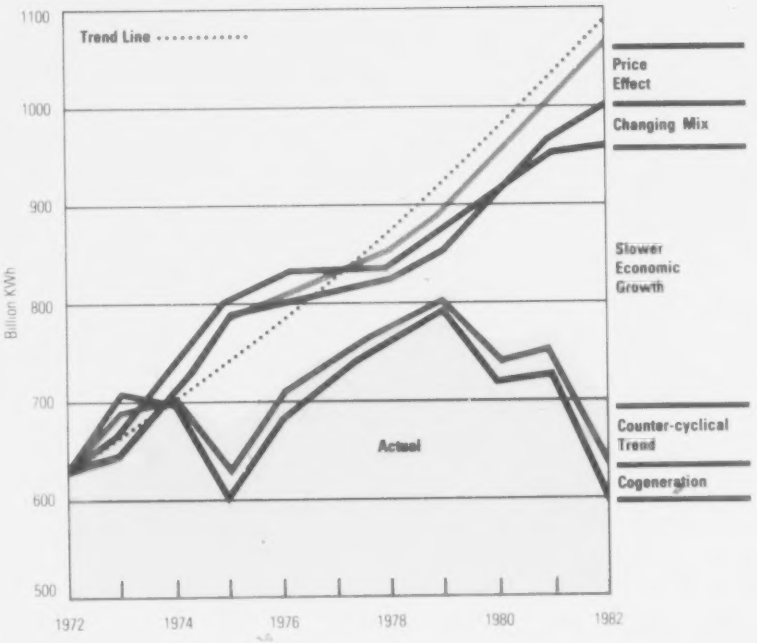
The Industrial Sector

In 1981 actual electricity purchases by the industrial sector, Figure 4, fell short of the trend projection by 33.5 percent. (Note: This analysis focuses on 1981 for the industrial sector because only very preliminary figures were available for 1982.) Had the price of electricity continued to decline at historic rates, actual demand in 1981 would have been 6.5 percent higher. Changes in the mix of industrial output reduced 1981 demand by 1.2 percent and preliminary 1982 demand by 6.6 percent. However, because this analysis compares actual with trends only, this reduction does not include the impact on demand caused by changes in output mix related to business cycles. The bulk of the deviation in actual from trend—70.4 percent—is accounted for by slower growth in real output.

Two remaining factors increased industrial demand. They are shown in Figure 4 beneath the line for actual demand. First, a sharp drop in cogeneration trend growth occurred as the price of fuels rose. If cogeneration growth had declined only moderately, as called for by the trend, electricity purchases would have been 3.3 percent lower in 1981. Second, because real industrial output tends to fall more sharply than electricity purchases during business cycle downturns, actual industrial demand was 3.3 percent higher in 1981 than it would have otherwise been.

Figure 4

Summary of Factors Affecting Industrial Electricity Purchases



In Retrospect

This analysis of electricity use explains to a large degree the slowdown in electricity demand during the seventies. Although slower economic growth was the overwhelming contributor to the reduction, conservation and technological changes prompted by higher real energy prices also noticeably affected demand. In contrast, the impact of the changing sectoral mix was not that significant a factor. To be an important factor in determining future electricity growth, the sectoral composition of the economy will have to shift more dramatically than it did in the 1970s.

By identifying the driving forces of electricity use, isolating their effects, and separating those factors that are likely to persist from those that were merely a result of the tumult of the 1970s, we can begin to assess the stability of the emerging trends that will determine the future of electricity consumption.

R E V I E W S

STATISTICAL REVIEW

1983 ELECTRIC OUTPUT

A strong upsurge in electricity demand during the last half of 1983 helped drive the annual output of electricity to an all-time high of 2,348 Terawatt-hours (TWh) for the year. (Note: one terawatt-hour is equal to one billion kilowatt-hours.) The previous annual record occurred in 1981 when electric output totaled 2,319 TWh, followed in 1982 by a drop of 2.2 percent to 2,267 TWh. The 1983 increase (3.6 percent) in output over 1982 was spurred by the improving economy, a much hotter summer than usual, and a much colder-than-normal December.

1983 in Review

As a result of mild weather and a continued low level of industrial production, electric output for the first quarter of 1983 dropped 3.8 percent compared with the first quarter of 1982, the largest quarter-to-comparable-quarter drop in the last 50 years. February, in particular, continued its three-year history of below-normal output. The largest decreases occurred in the industrial regions of the Midwest and Pacific Northwest, suggesting the recession's pronounced effect on output.

Table 1
Quarterly Electric Output (TWh)

Quarter	1983	1982	Percent Change
First	559.8	581.9	(3.8)
Second	547.8	541.7	1.1
Third	652.0	600.0	8.7
Fourth	588.0	543.3	8.2
Year	2,347.6	2,266.9	3.6

Source: Edison Electric Institute Weekly Electric Output

The second quarter showed the first signs of the economic recovery as electric output rose for the first time in five quarters. Although the improving economy pushed industrial demand for electricity up, relatively mild weather held electric output to a modest 1.1 percent increase over the second quarter. But in June, the summer heat wave began to roll across the country. The heat and, to a great extent, increased industrial and residential demand in the northern industrial states, accounted for most of the month's 4.1 percent increase in output.

During the third quarter both electric output and the economy showed increases. At 652 TWh, an 8.7 percent increase over the third quarter of 1982, output set a new quarterly record. The summer heat wave was the main cause of the increased electricity demand, along with increased demand by heavy industry in some areas. The four regions of the Midwest and Southeast all recorded increases of over 10 percent. All three months of the third quarter had record levels of electric output with August showing the highest monthly output total ever at 230 TWh, almost 11 percent greater than August 1982.

The fourth quarter began with modest increases of 4 to 5 percent in both October and November. Because the weather was roughly the same as in 1982, the increases can be attributed to the improving economy. In the last two weeks of December, electric output skyrocketed as a severe cold wave hit the country. By the end of the quarter, electric output had risen by a total of 8.2 percent, with the Central Industrial region leading the nation with a 19.5 percent increase. Rebounding from the trough of the recession that

REVIEWS

Figure 1.
Monthly Electric Output 1980–1983 (Terawatt-hours)

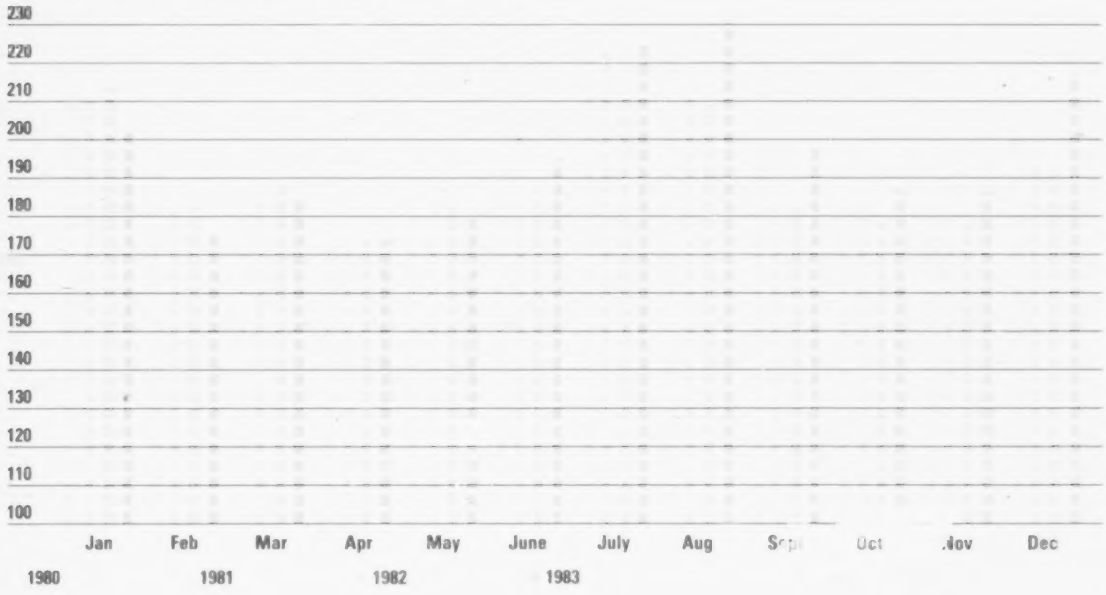
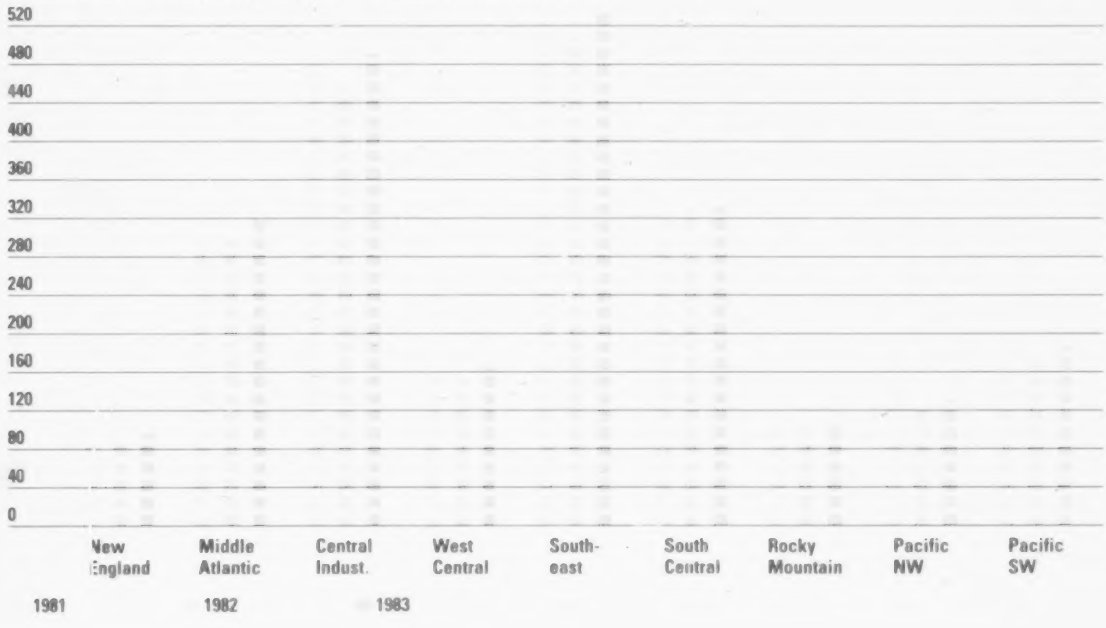


Figure 2.
Annual Electric Output by Region 1981–1983 (Terawatt-hours)



occurred during the fourth quarter of 1982, regions with a high concentration of heavy industry had the highest growth rates. All three months of the quarter had record levels of output, with the month of December recording the highest output for a winter month at 217 TWh, an increase of 14.5 percent over the previous December.

For the year as a whole, the Central Industrial, West Central, and Southeast regions all returned to pre-recession levels of electric output, even though industrial electricity demand is still relatively depressed. The New England and Middle Atlantic regions both had fairly large increases of 4.8 percent, while the South Central, Rocky Mountain, and Pacific Southwest regions had negligible increases. Only the Pacific Northwest region had a drop in output during the year.

Contributed by the Statistics Department of Edison Electric Institute

FINANCIAL REVIEW

ELECTRIC OPERATING REVENUES UP 11.2 PERCENT; ANNUALIZED GROWTH OF CWIP SLOWS TO 10 PERCENT THROUGH THIRD QUARTER

Total electric operating revenues of the investor-owned electric utility industry rose to $31.4 billion for the third quarter of 1983, an 11.2 percent increase over the comparable 1982 quarter, while electric operating expenses increased 9.6 percent to $24.9 billion. The net result is a 17.8 percent increase in electric utility operating income when compared with the third quarter of 1982.

Earnings per share for the three months ending September 30, 1983, were up 18.4 percent to $1.03, compared to 87 cents (revised) during the same period in 1982. Net income available for common stock shareholders during the quarter increased 28.9 percent over the earlier year's third quarter to $5.0 billion. The average number of common stock shares outstanding increased 9.3 percent to 4.9 billion shares in the third quarter of 1983 compared with the third quarter of 1982, the lowest percentage increase since the third quarter of 1980.

Predominant factors controlling the third quarter electric operating revenues increase were record kilowatt hour sales attained during the abnormally hot summer, increased industrial activity, and rate increases of prior periods. Total kilowatt hour sales to ultimate customers during the quarter soared 9.8 percent over the year-earlier quarter, a period marked by cooler-than-normal summer temperatures and a declining economy.

The increase in operating expenses during the third quarter was due in part to a 5.3 percent increase in fuel expenses during the same period, ending a pattern that began in the second quarter of 1982 whereby the industry's quarterly fuel expenses declined from the comparable quarter of the previous year. Despite higher fuel expenses, however, total electric operating expenses were only 79.3 percent of operating revenues, the lowest percentage since the third quarter of 1975. The impact of increased sales and continued cost containment more than offset the affect of the higher fuel expenses, pushing the percentage down.

Interest and Charges Increase Slows

Total interest and charges increased 4.0 percent during the third quarter of 1983 as interest on long-term debt increased 7.7 percent, the lowest quarter-to-comparable-quarter increase since the second quarter of 1976, and an indication of lower debt-financing requirements and lower interest rates. According to EBASCO Services, Inc., new taxable bond financings through the first three quarters of 1983 were $4.6 billion, 6.8 percent below the same period of 1982. "Other Interest Expenses and

R E V I E W S

Table 1

Investor-Owned Electric Utility Industry Statement of Income
For periods ending September 30, 1983 and 1982 (unaudited) (Millions of Dollars)

	Quarter Ending September 30,			Year Ending September 30,		
	1983	1982(R)	% Change	1983	1982(R)	% Change
Total Electric Operating Revenues	$31,400	$28,235	11.2	$105,742	$100,338	5.4
Electric Operating Expenses						
Fuel	10,475	9,949	5.3	35,333	36,823	(4.0)
Other Operation & Maintenance	6,437	6,278	2.5	25,996	24,142	7.7
Depreciation & Amortization	2,065	1,891	9.2	7,983	7,330	8.9
Taxes Other Than Income Taxes	2,104	1,881	11.9	7,618	7,025	8.4
Income Taxes (Federal & Other)	1,791	1,497	19.6	3,138	3,203	(2.0)
Provisions for Deferred Income Taxes—Net	1,323	622	112.7	3,773	1,898	98.8
Investment Tax Credit Adjustments—Net	701	597	17.4	2,162	2,065	4.7
Total Electric Operating Expenses	24,896	22,715	9.6	86,003	82,486	4.3
Electric Utility Operating Income	6,504	5,520	17.8	19,739	17,852	10.6
Other Utility Operating Income	77	77	0.0	1,026	1,131	(9.3)
Total Utility Operating Income	6,581	5,597	17.6	20,765	18,983	9.4
Other Income & Deductions—Net	452	431	4.9	1,475	1,822	(19.0)
Allowance for Other Funds Used During Construction	1,297	1,054	23.1	4,838	3,748	29.1
Total Income	8,330	7,082	17.6	27,078	24,553	10.3
Interest on Long-Term Debt	3,154	2,928	7.7	12,196	11,205	8.8
Other Interest Expenses & Charges	286	389	(26.5)	1,153	1,588	(27.4)
Allowance for Borrowed Funds Used During Construction (Cr.)	(801)	(780)	2.7	(3,102)	(2,917)	6.3
Total Interest & Charges	2,639	2,537	4.0	10,247	9,876	3.8
Net Income Before Extraordinary Items	5,691	4,545	25.2	16,831	14,677	14.7
Extraordinary Items	2	(34)	—	(50)	93	—
Net Income	5,693	4,511	26.2	16,781	14,770	13.6
Preferred Stock Dividends Declared	701	639	9.7	2,695	2,443	10.3
Net Income Available for Common	4,992	3,872	28.9	14,086	12,327	14.3
Common Stock Dividends	2,602	2,237	16.3	9,878	8,474	16.6
Retained Earnings	2,390	1,635	46.2	4,208	3,853	9.2
Earnings Per Share*	$ 1.03	$ 0.87	18.4	$ 2.98	$ 2.88	3.5
Dividends Per Share*	$ 0.53	$ 0.50	6.0	$ 2.09	$ 1.98	5.6

NOTE: The income statement is a "net" statement since the duplicative effect of including resale revenues by one investor-owned electric utility to another has been eliminated.

*Based on average shares outstanding as reported to EEI by survey respondents and adjusted for stock splits. (R) Revised

Table 2
Investor-Owned Electric Utility Industry Balance Sheet
As of September 30, 1983 and 1982 (unaudited) (Millions of Dollars)

Assets	1983	1982	% Change
Utility Plant*			
Utility Plant (Including Nuclear Fuel)	$269,096	$243,890	10.3
Less Accumulated Depreciation	75,697	68,693	10.2
Less Property-Related Accumulated Deferred Income Taxes	3,922	3,198	22.6
Total	$189,477	$171,999	10.2
Construction Work in Progress	97,239	90,187	7.8
Net Utility Plant	$286,716	$262,186	9.4
Investments	6,325	5,843	8.2
Current Assets	32,871	30,271	8.6
Deferred Debits	8,649	7,264	19.1
Total Assets	$334,561	$305,564	9.5
Capitalization & Liabilities			
Capitalization			
Common Stock Equity	$ 72,124	$ 64,259	12.2
Retained Earnings	34,635	30,763	12.6
Preferred Stock	30,963	29,205	6.0
Long-Term Debt	129,252	120,525	7.2
Total Capitalization	$266,974	$244,752	9.1
Current Liabilities			
Short-Term Debt	$ 5,110	$ 6,328	(19.2)
Long-Term Debt Due Currently	3,734	3,269	14.2
Other Current Liabilities	24,313	22,015	10.4
Total Current Liabilities	$ 33,157	$ 31,612	4.9
Deferred Credits			
Accumulated Deferred Income Taxes	$ 17,417	$ 14,546	19.7
Accumulated Deferred Investment Tax Credits	12,079	9,957	21.3
Other Deferred Credits	4,934	4,697	5.0
Total Deferred Credits	$ 34,430	$ 29,200	17.9
Total Capitalization & Liabilities	$334,561	$305,564	9.5

*Includes other utility plant of combination gas and electric companies.

Charges" declined 26.5 percent, due in part to the lower volume of short-term debt outstanding, which declined 19.2 percent to $5.1 billion at the end of the third quarter, compared with $6.3 billion a year earlier.

For the 1983 third quarter, interest coverages before taxes and with allowance for funds used during construction were 3.76 times; that is, income, including AFUDC, before interest and taxes was 3.76 times the interest expense on long- and short-term debt. Interest coverages for the same period in 1982 were 3.19 times. Interest coverage was 2.94 times and 2.71 times for the 12 months ending September 30, 1982 and 1983 respectively.

AFUDC Growth Rate Decreases

The rate of increase from quarter-to-comparable-quarter in AFUDC slowed during the third quarter as total AFUDC increased 14.4 percent, down from the industry's peak rate of increase of 26.4 percent in the fourth quarter of 1981, and the lowest since the first quarter of that year. For the year ending on September 30, 1983, AFUDC increased 19.1 percent.

AFUDC accounted for 42 percent of third quarter 1983 net income available to common stock shareholders, compared to 47 percent in the third quarter of 1982. This decrease reflects in large part the higher level of earnings resulting from higher third quarter sales. AFUDC as a percent of net income available to common stockholders was 56 percent for the 12 months ending September 30, 1983, compared to 54 percent for the comparable period a year earlier.

Return on Equity Increases

The industry's return on average common equity (ROE) also benefited from the strong third quarter earnings. ROE increased to 14.0 percent based on net income available to common stock shareholders for the twelve months ending September 30, 1983. Total common stock equity as of September 30, 1983, was $106.8 billion, 12.4 percent greater than a year before.

CWIP Slows

Construction work in progress (CWIP) increased 7.8 percent in the 12 months ending September 30, 1983, to $97.2 billion. However, through the first three quarters of 1983, CWIP was increasing at an annualized rate of only about 10 percent, the lowest annual rate in 13 years.

Tables 1 and 2 are based on unaudited reports received from electric utilities. The utilities account for about 95 percent of the industry's revenue from sales to ultimate customers and 94 percent of the industry's total assets. The data was expanded to represent the entire industry.

Contributed by the Finance Department of Edison Electric Institute.

TECHNOLOGY REVIEW

FUEL CELLS: SPACE AGE TECHNOLOGY

Fuel cells could generate up to 45,000 megawatts of electric power by the year 2005 according to Ed Gillis, Program Manager for the Electric Power Research Institute (EPRI).

Already used to supply power on board the Space Shuttle, the technology now is being studied at an experimental 4.5-megawatt facility in New York City. "Research now underway at that facility is a major step toward giving the nation's electric utilities a new option for power production," Gillis says.

Invented in England in 1839, the fuel cell has neared commercial development only within the last few years. Commercial fuel cell power plants are expected to be operating and generating power later in this decade.

Like a battery, the fuel cell uses an electrochemical process to transform the energy of a fuel and an oxidant continuously into electricity. But unlike a battery, a fuel cell does not run down and require recharging. It will operate as long as both fuel and oxidant are supplied to its electrodes.

Attracted by the fuel cell's high conversion efficiency (up to 50 percent in the near future), quiet operation, quick installation, and virtual lack of polluting emissions, private and government institutions have spent more than $100 million to develop the technology.

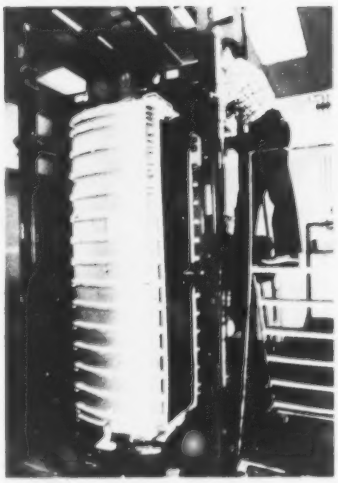
Project sponsors for the Manhattan plant include EPRI, the

U.S. Department of Energy, United Technologies Corporation (UTC), and a utility consortium led by Consolidated Edison that includes the Empire State Electric Energy Research Corporation, New York State Energy Research and Development Authority, Niagara Mohawk Power Company, and Northeast Utilities.

"Fuel cell technology can supply electricity in urban areas where fossil-fired generators are environmentally unacceptable because it doesn't produce unwanted emissions," Gillis explains. "Also, since these plants can be built close to where the electricity is needed, the need for expensive high voltage transmission lines can be eliminated."

Fuel cell power plants also can respond to power demands very quickly. A commercial fuel cell plant should be able to reach full power from standby within 15 seconds. Such quick response makes them ideal candidates for use during peak-demand periods.

Electric utilities serving urban markets probably will be the best customers for fuel cell power plants. "Small, modular plants with capacities of 7 to 11 megawatts would be transported by truck to sites close to new industrial parks and major commercial centers where the electricity is needed. No new transmission networks would be needed," Gillis says.



One of 20 fuel cell stacks at the Manhattan demonstration plant.

Moreover, as power plant capital costs decrease, the market will expand to include industrial and commercial organizations for cogeneration applications. "In electric service only, utilities are likely to operate the units in cycling duty to meet peak demand," Gillis explains. "Where cogeneration opportunities exist (up to 80 percent of the fuel energy is recoverable as electricity, steam, and hot water) the units will be operated close to base load."

In a fuel cell, two porous electrodes with good electrical conductivity contact a liquid or solid electrolyte. Fuels such as naphtha or hydrogen then are introduced at one of the electrodes. At the interface between the electrodes and the electrolyte, two electrochemical reactions take place: the fuel is oxidized while the oxygen is reduced.

This oxidation process releases electrons, and the reduction process absorbs electrons. Connecting the two electrodes, which serve as reaction sites or catalysts, in an external circuit produces direct-current electricity. A power converter then converts the direct current to alternating current.

Each typical fuel cell produces less than one volt. Higher voltages are generated by connecting the cells in a series commonly known as a "cell stack."

The New York facility contains 20 stacks of more than 400 flat, square, sandwiched cells measuring about 2 feet on each side. Each stack is about 8 feet high. The plant uses natural gas or naphtha for fuel, but most experts see commercial fuel cell plants using natural gas.

Another 4.5-megawatt power plant of the type built in Manhattan successfully demonstrated the technology in Tokyo, Japan, in April, 1982. Manufactured by UTC and purchased by Tokyo Electric Power Company, it is identical to the Manhattan facility except for the use of improved fuel cell stacks. Researchers were able to take advantage of the lessons learned in building the New York plant.

"While these 4.5 megawatt units are not commercial power plants, they are part of an evolutionary process that should lead to commercial designs," Gillis says.

R E V I E W S

"In fact, second generation equipment is now planned for the commercial market."

Both Westinghouse Electric Operations and UTC are working on commercial power plant designs. UTC expects to have an 11-megawatt prototype ready by 1986. Westinghouse will deliver two 7.5 megawatt units in 1987.

A Fuel Cell Users Group of more than 50 utility organizations and other interested parties has been working closely with UTC and Westinghouse to define the preferred plant design, operating characteristics, near- and mid-term applications, and commercialization strategies.

Another users' group, made up of several potential industrial users, recently has formed to look at issues of interest in the industrial sector.

"The fuel cell power plant," Gillis says, "once a dream to many of us in the field, is now on the verge of reality."

Contributed by the Information and Publishing Services Department of Edison Electric Institute.

REGULATORY REVIEW

THE COST OF ACID RAIN CONTROL

By A. Joseph Dowd

Scientific uncertainties surround almost every facet of the acid rain issue. Suffice it to say that, at present, nobody can predict with any reasonable degree of assurance whether or not massive SO_2 emissions reductions in the Midwest would produce even perceptible ecological benefits in the Northeast or Canada, what the relative influences of long-range versus local emissions sources are, or the extent to which acidity from terrestrial factors, rather than from atmospheric deposition, is responsible for whatever aquatic acidification may be occurring.

While these kinds of uncertainties abound, and should be of controlling importance in any legislative resolution of the issue, there is also the question of how much it will cost to implement any of the legislative remedies currently under consideration, the scientific merits of proposed plans to do so notwithstanding.

Economic Analyses

Recently, several national environmental groups, with the help of the independent economic consulting firm ICF, Inc., predicted that reducing SO_2 emissions by 10 million tons over the 31-state ARMS (Acid Rain Mitigation States) region would cost electric utilities $14.7 billion in initial capital requirements and $2.8 billion in annual costs thereafter. It was assumed for this analysis that cost-free interstate SO_2 reduction credits would be maximized and that emissions increases resulting from future economic growth would not have to be offset.

In another study, conducted for the Edison Electric Institute (EEI), ICF projected that the 10-million-ton reduction program proposed in legislation by Senator George Mitchell (D-ME) would impose capital costs of $26.2 billion and annual operating costs of $6.9 billion. ICF projected that these costs would result in an average electric rate increase across the ARMS region of 6.1 percent, but with much higher increases in the Midwest. Interstate trading of emissions credits was not assumed, in view of its dubious potential, and, as specified in the Mitchell bill, emission offsets were required.

Using its own macroeconomic analytical approach, the Department of Energy independently predicted that the annual cost of a 10-million-ton SO_2 reduction over the ARMS region would range from $2 to $6 billion in 1980 dollars. Over a 30-year period, the cost amounts to $200 to $300 billion.

More recently, at EEI's request, the consulting firm of Temple, Barker and Sloane examined the costs likely to be imposed by H.R. 3400, the Waxman/Sikorski bill. This bill would

require a 10-million-ton reduction in SO_2 emissions over an area slightly different from the ARMS region, with a proviso that roughly two-thirds of the rollback be achieved through scrubbing. It was estimated that the levelized cost of compliance would amount to $7.9 billion annually and that the total price tag through 2008, including the impact of inflation, would be $222 billion.

One can raise questions—indeed almost everybody has—about each of these analyses. But they all have one thing in common: they all project multi-billion-dollar annual costs.

While macroeconomic models serve a useful purpose in providing a broad-brush, first-cut approach to complex problems, we, the members of the investor-owned electric utility industry, are concerned that, because such models generally assume a frictionless environment in which all opportunities are totally maximized, they tend to underpredict substantially the true cost of the various control scenarios. Also, the models cannot take into account the multiplicity of site-specific factors, such as space limitations, plant age, boiler design, fuel supply, the relocation of existing systems, and the difficulty of disposing of scrubber sludge, which all inevitably have the effect of pushing costs well above those predicted by the models.

Company-Specific Impacts

In 1983, because of these concerns, 24 electric utilities, under the auspices of EEI, and with the guidance of an independent economic consulting organization, embarked upon company-specific studies of the cost impact of the Stafford bill (S. 768). The Stafford bill was chosen because it is the only acid rain control bill ever to be reported out of committee and because it appears to be the least Draconian of the pending bills in that it calls for an 8-ton SO_2 reduction and provides compliance deadlines of 1993 and 1995.

The projected compliance costs reported by the 24 utilities indicate that achieving their share, approximately 44 percent, of the 8-million ton SO_2 reduction would require initial capital costs in excess of $15 billion, first-year operating costs of more than $5 billion, or, with operating costs levelized over five years, more than $4 billion annually. More than one-third of the utilities indicated that first-year electric rate increases would exceed 20 percent and that, on a levelized basis, increases over five years would exceed 15 percent annually. Companies in Ohio and Indiana would be hit harder than others, with first-year increases of about 50 percent and levelized increases over the first five years of about 35 percent.

Exaggerated Estimates?

These industry cost estimates have been criticized as being too high—even as being deliberately exaggerated. First, it is alleged that the use of first-year costs is misleading because the costs gradually decline after the first year. But first-year costs *will* be very high, and our customers have a right to know it, and we have an obligation to tell them. Yes, the costs do gradually decline after the first year, and this is why we took the alternative approach of levelizing our cost figures over the first five years of compliance.

A second and related criticism is that we included the total cost of replacing prematurely retired plants in our studies, even though such plants would in the natural course of events have gone on line a few years later. The fact of the matter is that if new, high-cost plants go on line earlier than they otherwise would have, the *total* annual cost associated with that expensive replacement capacity will be incurred in those early years and, therefore, should be reflected in our studies.

A third criticism is that since the electric utility industry generally is in an "excess capacity" situation today, generating capacity lost as a result of acid rain controls does not have to be replaced, and, therefore, emission reductions affected in this

manner are "cost-free." This argument, of course, is absurd. First of all, this excess capacity may prove illusory. For example, due to the heat wave last summer three companies of the American Electric Power System established new summer peaks and a fourth established an all-time peak. Also, emission reductions effected through premature plant retirements by definition cannot be cost free. The mere fact that such retirements are premature means that those plants would have been serving load into the future had it not been for the imposition of acid rain controls. That load then either must be carried by new, higher-cost replacement capacity or it must be shifted to more expensive existing capacity. In either case a cost obviously is incurred. In addition, the retrofitting of scrubbers onto existing power plants effectively will reduce the generating capacity of those plants. Approximately 5 percent of the electricity generated by a power plant is consumed in the operation of its scrubbers. Furthermore, because of the addition of this highly complex piece of chemical equipment—with its potential for periodic breakdown—the power plant's availability is reduced by as much as 4 to 5 percent. Thus, by way of illustration, today we have a hypothetical 1,000-megawatt generating unit. Tonight we retrofit it with a scrubber. Tomorrow morning we have what is effectively a 900-megawatt unit. Regardless of the so-called excess capacity situation, it cannot be denied that there is an economic cost to society involved in the loss of this 100 megawatts of good generating capacity.

The industry's numbers also have been criticized on the grounds that they reflect a high-cost scrubber-retrofit scenario rather than a least-cost fuel-switching scenario and, consequently, are overstated. That is not accurate, and, where feasible, fuel-switching was assumed. Scrubber retrofits were employed in many cases because we believed that that is what the industry ultimately would be required to do, not because we want to exaggerate costs. Those utilities located in regions of Appalachia and the Midwest that have high-sulfur coal are convinced that as a practical matter they would never be permitted to switch *en masse* away from their coal supply. This view is reinforced by the fact that §125 of the Clean Air Act—the so-called Metzenbaum Amendment—is still on the books and, presumably, would be invoked in an effort to prevent the severe economic hardship and human suffering that would result from *en masse* fuel switching.

The TVA Experience

In addition to these criticisms, the TVA experience has been misused by some in an effort to undermine the credibility of the electric utility industry's cost studies. TVA—admittedly a great electric utility system—says that it has reduced its SO_2 emissions by one million tons since the mid-1970s at a capital cost of about $750 million, resulting in a rate increase of only about 7 percent. Why then are the other electric utilities' numbers so high?

First of all—and this is not generally understood—TVA's reductions were made from a very high baseline. In 1974 its system-wide average SO_2 emission rate was about 6 lbs. per million BTU (5.95 lbs. to be exact). By comparison, in 1974 the American Electric Power System had a system-wide average SO_2 emission rate of 4.05 lbs., which it since has reduced to about 3.7 lbs. Obviously, it is a lot easier and a lot less expensive to cut a million tons from a 6-lb. level than from a 3.7-lb. level. This then, is one very major reason why TVA's costs were so low. Most simply put, its emissions were very high.

Second, in carrying out its emissions reduction program, TVA was in a position to place very heavy emphasis upon

switching to low-sulfur coal—a low-cost strategy that is probably unavailable to those utilities in the Midwest that would have to bear the brunt of proposed acid rain controls.

Third, a certain portion of TVA's net reductions resulted, in the natural course, from already planned construction of non-fossil-fired capacity. Thus, during the period subsequent to the mid-1970s, TVA placed in service 2,440 megawatts of non-SO_2-emitting nuclear capacity. This base-load nuclear capacity displaced a significant portion of TVA's coal-fired generation, but its cost, quite properly, was not included in TVA's SO_2 emission reduction figures.

Fourth, because TVA has a much heavier component of nuclear and hydro capacity than do the midwestern utilities, it was able to spread the costs of reducing its SO_2 emissions thinly over its total generation mix. In 1982 TVA was only 55 percent coal. Contrast this with the slightly smaller American Electric Power System (22,000 megawatts versus TVA's 29,000 megawatts), which in 1982 was 87 percent coal-fired. Forty-five percent of TVA's capacity was totally unaffected by emissions reductions. Its nuclear- and hydro-generated kilowatt-hours effectively diluted the cost per kilowatt-hour of its reduction program and helps to explain why the resulting increase was as low as TVA claims. The fact that TVA is scheduled to bring almost 5,000 megawatts of non-SO_2-emitting nuclear capacity on line later in this decade also helps explain why it projects that an 8-million-ton emissions reduction requirement would result in its increasing electric rates by only 3 to 6 percent.

Clearly, the TVA experience has only the most limited relevance to the present debate regarding acid rain control costs.

Uncertain Remedy

It should be evident that the cost to the nation of implementing any of the proposed acid rain controls will be great, regardless of whether their direct impact is concentrated in one already depressed geographic region or spread more thinly over 31 or 48 states. Moreover, there is no scientific certainty that environmental benefits commensurate with this cost will result, or indeed, that any perceptible benefit will result at all.

Joseph Dowd is Senior Vice President and General Counsel for American Electric Power Service Corporation of Columbus, Ohio. This article is based on a speech he made in late 1983 to the Coalition of Northeastern Governors.

FOR PERSPECTIVE

FORECAST COMPARISONS

Numerous studies have appeared over the past several years presenting energy consumption and supply forecasts. Although all of these reports project electricity demand to grow faster than total energy demand, none foresees a return to the historical long-term growth rates. A review of projected growth rates in the 12 studies presented here, ranked by electricity/GNP growth ratio, shows that, in general, the projected growth rate for GNP, energy, and electricity are within a comparable range, except for the scenarios described in the study, *A Desirable Energy Future,* which projected much higher energy consumption:

- GNP assumptions to the year 2000 call for an average annual growth rate of 2.4 to 2.9 percent.
- In most of the studies, primary energy consumption is forecast to grow at an average annual growth rate between 1.0 and 1.4 percent. Only the Wharton, *A Desirable Energy Future* (Case B), and Energy Information Administration studies project a higher growth rate—1.8 to 2.4 percent annually.
- While total end-use energy consumption is expected to grow at an average 0.3 to 1.1 percent annually, electricity end-use consumption is projected to increase by 2.3 to

Table 1

Energy Supply and Demand Forecasts Average Annual Growth Rates

	GNP	Primary Energy Consumption	Electricity Consumption	End Use Energy	Electricity/GNP Growth Rate Ratio
ADEF (B) 1979-2000	2.6[1]	2.4	4.9	1.0	1.91
ADEF (A) 1979-2000	2.6[1]	1.4	3.5	0.3	1.37
EEI Continuation 1978-2000	2.4	1.3	3.2	0.8	1.33
Starr-Searl 1979-2000	2.5	N/A	3.2[2]	N/A	1.28
EIA 1982-1990	3.2	1.8	3.8	1.1	1.19
DOE/OPPA[3] 1982-2000	2.8	1.4	2.8	0.9	1.00
Wharton 1982-2000	2.9	2.0	2.6	N/A	.90
DRI 1982-2000	2.8	1.3	2.4	0.9	.86
Gustaferro 1982-2000	2.8	1.0	2.3	0.5	.83
GRI 1982-2000	2.9	1.4	2.3	1.2	.80
AAES 1980-2000	N/A	1.3	3.2	0.5	N/A
NERC 1983-1992	N/A	N/A	3.2	N/A	N/A

Notes

[1] Based on a 2 percent growth rate in real per capital GNP. [2] Based on 1980-2000. [3] Based on 1982 estimate.
N/A = Not Available

Legend:

ADEF: Livingston, Robert S., et. al., 1982. *A Desirable Energy Future—A National Perspective.* Oak Ridge National Laboratory, Oak Ridge, Tennessee.

EEI: Thompson, William F., Karaganis, Jerome J., and Wilson, Kenneth D., 1981. *Choice over Chance* (Sponsored by Edison Electric Institute.) Praeger Publishers, New York.

Starr-Searl: Starr, Chauncey and Searl, Milton F. "U.S. Generating Capacity Requirements for Economic Growth, 1990-2000." *Public Utilities Fortnightly,* Arlington, VA. April 29, 1982.

EIA: U.S. Department of Energy, Energy Information Administration. *1982 Annual Energy Outlook—With Projections to 1990.* DOE/EIA-0383 (82) April 1983.

DOE/OPPA: U.S. Department of Energy. *Energy Projections to the Year 2010—October 1983.* U.S. Department of Energy, Office of Policy Planning And Analysis, Division of Analytical Services. DOE/PE-0029/2.

Wharton: Wharton Econometrics, August 1983. *Long Term Model to the Year 2002.* Philadelphia, Pennsylvania.

DRI: Data Resources, Inc., Autumn 1983. *Energy Review.* Lexington, Mass.

Gustaferro: Gustaferro, Joseph F., July 2, 1983. *U.S. Energy for the Rest of the Century.* U.S. Department of Commerce, Washington, D.C. 20230.

GRI: Gas Research Institute, October 1983. *1983 GRI Baseline Projection of U.S. Energy Supply and Demand, 1982-2000.* Gas Research Institute, Chicago, Illinois.

AAES: American Association of Engineering Societies, Inc. March 1983. *National Energy Statement II, March, 1983.*

NERC: National Electric Reliability Council. Electric Power Supply and Demand 1983-1992. Princeton, New Jersey, July 1983.

3.2 percent annually, except in the *A Desirable Energy Future* analyses, which estimate electricity consumption to grow by 3.5 to 4.9 percent annually to 2000, and the Energy Information Administration analysis, which projects an annual growth rate of 3.8 percent to 1990.

- The electricity/GNP ratio ranges from a high of 1.91 in *A Desirable Energy Future* to a low of .80 in the Gas Research Institute estimate. Of note is that the older studies tend to show a higher electricity/GNP ratio. These studies also focus on exploring alternative desirable scenarios rather than projecting a "most likely" future.

Contributed by the Energy Modeling and Research Department of Edison Electric Institute.

BOOK REVIEW

REFORMING FEDERAL REGULATION

Robert E. Litan and William D. Nordhaus
Yale University Press, 1983
New Haven, 204 pp.

By Bruce G. Humphrey

As reliance on regulation as a mechanism to pursue national objectives has grown dramatically in the past decade, so has the discontent with government interference in American life. While there is a broad consensus on the importance of pollution control, worker safety, consumer safety, financial market stability, economic competition, and other regulatory objectives, there is a strong feeling that the agencies pursuing these objectives are outside of the system of checks and balances that characterizes our political institutions. There is the impression that these agencies have unchecked power to coerce behavior and divert private resources to promote their narrow objectives. Regulatory reform therefore has become the focus of considerable debate and public policy interest.

The last three administrations have taken steps to establish greater oversight of the regulatory actions taken by agencies within the Executive Branch. Presidents Ford, Carter, and Reagan each issued executive orders requiring greater consideration of the economic effects of proposed rules before they were issued. Both Robert Litan and William Nordhaus participated in the regulatory reform debate during the Carter Administration and were among those responsible for implementing requirements that agencies describe and justify the economic consequences of their regulatory proposals. Nordhaus was a member of the President's Council of Economic Advisors and Litan served on the Council staff. *Reforming Federal Regulation* draws upon this experience and reflects the continuity of effort through three administrations to improve the cost-effectiveness of federal regulations. The presentation is cogent and essential reading for anyone seeking to participate in the ongoing regulatory reform debate.

The suspicion that regulations could be better designed and managed is buttressed by substantial evidence. To begin with, at least 80 agencies have the authority to promulgate regulations. These agencies impose compliance costs on the private sector of at least $50 billion per year. They also appear to impose contradictory requirements. Litan and Nordhaus retell the often cited example of a meat packing company being told by one federal agency to wash its floors several times a day for cleanliness and by another to keep its floor dry at all times to prevent employee accidents. The sheer number of regulations also is imposing. The steel industry must comply with over 5,000

regulations administered by 25 federal agencies as well as numerous state and local agencies. Finally, numerous studies have documented the inflationary impacts, the lost productivity, and the opportunity costs of many regulations.

Regulatory reform has addressed these issues on two levels. First, efforts have been made to assure a better balance between the costs and benefits of individual regulations prior to their issuance. Second, proposals have been made to establish oversight of the regulatory system as a whole in order to balance the priorities of the myriad national objectives pursued by regulation. Litan and Nordhaus trace the recent history and critique the efforts to improve individual regulations. The authors' main theme and policy prescriptions address the second level of reform.

Recent efforts to improve individual regulations are an essential part of the story. In addition to the executive orders implemented by recent administrations, other mechanisms have been proposed. *Sunset legislation* would provide for the expiration of regulatory programs unless they specifically were reenacted by Congress. *Legislative veto* would subject regulatory agency actions to overrides by vote of one or both houses of Congress. *Presidential oversight*, as proposed by the American Bar Association, would by statute authorize the President to direct regulatory agencies to decide or reconsider critical regulatory issues and to modify or reverse certain actions. *Judicial review*, as embodied in the Bumpers Amendment, would require that regulators assume the burden of proof regarding the legitimacy of their actions when they are challenged in the courts.

As central as these mechanisms have been to the regulatory reform debate, they fail to address what is perhaps the most serious flaw regarding federal regulation—the lack of any mechanism to manage the costs of, and set priorities for, regulatory activities as a whole.

One of two key aspects of the regulatory management problem is that, unlike virtually every other area of government activity, regulatory agencies operate without the discipline of a budget mechanism. These agencies have virtually unlimited power to divert private resources to regulatory compliance. Conversely, even national defense, perhaps the highest national priority, is subject to budget limitations. The difficulty in managing regulatory activity in a budget-like manner is that costs are imposed on the private sector rather than funded from government revenue. The costs are difficult to observe and do not enter the traditional appropriations process. This characteristic, however, makes them no less of a burden on national resources.

The other key aspect of the regulatory management problem is the strict compartmentalization of regulatory responsibilities. Not only does this lead to ludicrous situations such as that faced by the meat-packing plant, but more generally, the current system does not allow trade-offs between competing priorities or reallocation of public and private resources across agency lines. For example, an administrator of the Occupational Safety and Health Administration cannot allocate a portion of either the agency budget or private resources spent on OSHA compliance to the Food and Drug Administration even though doing so may be in the national interest by providing greater safety benefits.

Litan and Nordhaus offer two proposals to deal with the lack of overall regulatory oversight. Their first proposal is the implementation of a *regulatory budget*. A regulatory budget would be a document prepared annually showing all federal expenditures for regulatory activities along with private sector expenditures for compliance. The authors foresee using the regulatory budget to set priorities across regulatory programs and to impose limits on the compliance costs that a regulatory agency could impose on the private sector. This is conceptually appealing but, the authors reluctantly conclude, unworkable because cost calculations are controversial and cost limits would be very difficult to enforce.

Their second proposal is for a

legislated regulatory calendar. This calendar would be an annual list of proposed rulemakings with preliminary analyses of projected costs and benefits. It would be submitted by the President to the Congress and provide a vehicle for debate about the dollar magnitudes and priorities reflected in the full range of regulatory actions. The calendar then would be authorized by the Congress. Although it is less complete conceptually because of less stringent information requirements, the regulatory calendar offers a practical alternative to a full-fledged regulatory budget.

As one of the most heavily regulated industries, electric utilities should have an active interest in the fundamental regulatory reform debate. Because utilities are subject to regulations by numerous federal agencies, they are in a better position to evaluate the comparative costs and effectiveness of the broad range of requirements imposed upon them than are the regulatory agencies themselves. From their perspective, it is apparent that a regulatory oversight mechanism should be instituted. Moreover, the mechanism should allow regulations to be assessed from the broadest possible perspective.

Either a regulatory budget or a legislated regulatory calendar could be such a mechanism. Litan and Nordhaus' reluctant abandonment of the regulatory budget option is premature; the approach is not fatally flawed by the impossibility of creating a strict, accounting-like framework.

A regulatory budget can be seen from at least three perspectives. It can be an informational mechanism, a policy-management mechanism, or, as viewed by Litan and Nordhaus, an expenditure control device.

As an informational mechanism, a regulatory budget would involve statistical reporting of regulatory expenditures into a regulatory data base similar to the existing national income accounting and census function currently carried out independent of the policy process.

An alternative approach would be to have a regulatory budget in the policy arena at the outset. In this case, a regulatory budget exercise would be part of the process of implementing regulations. Regulatory budget goals would be established not as absolute ceilings but as a very important component in the set of considerations determining a policy decision. These goals would be set by the President in light of historical behavior, expected costs, and current national priorities. The goals may or may not be subject to congressional review. Such a regulatory management system would require that the President have some authority to direct regulatory decisions.

A third alternative would be to have a regulatory budget process completely analogous to the existing fiscal budget process as Litan and Nordhaus discuss. This would involve development of a regulatory budget by the President; review, enactment, and oversight by the Congress; and, implementation by the Office of Management and Budget or a similar organization. Budget ceilings would be enforced. Regulatory decisions would be controlled by the regulatory budget.

The regulatory budget proposal is not without its problems. On balance, however, implementing a regulatory budget is a worthy next step in efforts to improve regulatory management. It does not have to be a rigid control device to be beneficial. On the other hand, it must be more than a regulatory cost-information system to have an impact.

Not only can the regulatory budget be viewed as a technical management device, but it also can be viewed as a mechanism for promoting the openness of government. Imposing a regulatory budget process on government agencies is similar to existing disclosure requirements imposed on the private sector. Just as lenders must disclose true interest rates and food processors must disclose the contents of their packaged products, the regulatory agencies would disclose the full costs of their actions. In effect, the regulatory budget proposal is a proposal for truth in regulating.

Bruce Humphrey is Director of Energy Modeling and Research for Edison Electric Institute.

M E E T I N G S

EDISON ELECTRIC INSTITUTE

April 4–7
EEI Legal Committee
San Diego, California
Robert Baum

April 10–12
EEI Affirmative Action Seminar & Workshop
Atlanta, Georgia
Ed Bomsey

April 16–18
EEI Construction Committee Topical Conference
St. Louis, Missouri
Eric Haskins

April 17–19
EEI Quality Assurance Committee
Little Rock, Arkansas
Suzanne Phelps

April 25–27
EEI Interconnection Arrangements Committee
Columbus, Ohio
Martin Gordon

April 28–May 2
EEI Prime Movers Committee
Miami, Florida
James Evans

April 29–May 1
EEI Rate Research Committee
Buffalo, New York
David Owens

May 2–4
EEI CS&M Division Annual Conference
Minneapolis, Minnesota
Charles Taylor

May 6–9
A.G.A.-EEI Internal Auditing Committees
New Orleans, Louisiana
Marshall Baker

May 7–8
A.G.A.-EEI Information Systems Committees
Milwaukee, Wisconsin
Ralph Palmigiano

May 8–10
EEI Labor Relations Conference
Washington, D.C.
Ed Bomsey

May 8–11
EEI Risk Management Committee
Williamsburg, Virginia
Ted Gradin

May 9–11
EEI Statistical Committee
Philadelphia, Pennsylvania
Thomas Daugherty

May 14–16
A.G.A.-EEI Customer Services Committees
Boston, Massachusetts
Robert Griffin

May 14–16
EEI Electrical System & Equipment Committee
Wilmington, North Carolina
Jamei Goellner

May 15–17
EEI Hydraulic Power Committee
Seattle, Washington
James Evans

May 15–17
EEI Compensation & Benefits Committee
Portland, Oregon
James Stroop

May 15–18
EEI Transmission & Distribution Committee
Indianapolis, Indiana
David Soffrin

May 15–18
A.G.A.-EEI General & Plant Accounting Committees
San Francisco, California
George Brown

May 16–17
EEI Spring Corporate Planning Meeting
Kansas City, Missouri
Sue Lerner

May 17–18
EEI Finance Committee Annual Meeting
New York, New York
Ted Gradin

May 17–18
EEI Fossil Fuel Committee
Baltimore, Maryland
Charles Linderman

May 20–23
EEI Purchasing & Stores Committee
Tampa, Florida
Martin Gordon

May 21–23
EEI Consumer Affairs Subject Area Committee Meeting/Workshop
Albuquerque, New Mexico
Charles Taylor

May 23
EEI Codes & Standards EAC
Philadelphia, Pennsylvania
John Markey

May 23–25
EEI Environment & Energy Committee
Denver, Colorado
Victoria Hull

June 4–6
EEI Chief Accounting Officers Meeting
San Francisco, California
George Brown

June 5
EEI Seminar on Current SEC Developments
Washington, D.C.
Ted Gradin

June 10–13
EEI Taxation Committee Meeting
El Paso, Texas
Ted Gradin

June 18–20
EEI 52nd Annual Convention
Boston, Massachusetts
John Mahoney

For further information on any of the meetings listed, call the contact person indicated at 202/828-7400.

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SUMMER 1984

EP ELECTRIC PERSPECTIVES

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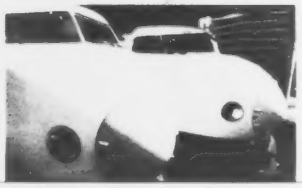

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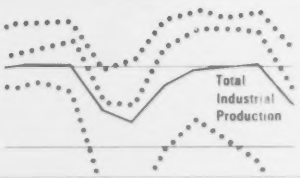

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THE CLEAN AIR ACT AND ACID RAIN

Proposed 'controls' could push the law's multi-billion dollar annual compliance price tag significantly higher.

By Eugene M. Trisko

Gene Trisko is an attorney in Washington, D.C., and advisor to Stern Bros., Inc., an energy holding company.

No federal law has had a greater impact on the electric utility industry than the Clean Air Act. Enacted in 1970 to "protect and enhance" the nation's air quality, the Act has allowed the United States to enjoy improved air quality while accommodating large increases in fossil fuel use. But this progress has not been achieved without costs: in compliance with ever-changing state and federal regulations, in related delays and uncertainty, and in the actual installation and use of pollution controls. The price tag for air pollution control now exceeds $25 billion annually, and most of this is paid by the electric utility industry and its customers.[1] According to public opinion polls, the Clean Air Act continues to enjoy strong popular support.[2]

The Clean Air Act is now before Congress for reauthorization, and lawmakers are pondering changes to its compliance deadlines and operating programs. The most important question Congress will address is whether additional emission controls are needed to reduce acid deposition. The outcome of this debate could have profound financial and regulatory implications for utilities and users of electricity.

The acid rain issue has paralyzed the Clean Air Act reauthorization debate since 1981, and it shows no signs of early resolution. At stake for the electric utility industry and its customers are additional compliance costs of $4 to $10 billion per year or more. The environmental effects of such a program are extremely uncertain. And at the same time, it is reasonable to expect that the Act's current path to air quality improvement will yield future emission reductions similar to those called for by proposed acid rain control bills over a roughly comparable period of time. The chief difference between the two paths is economic: new controls intended to combat acid rain would cost society hundreds of billions of additional compliance dollars over the life of such a program, and thus would divert capital from the production of other goods and services.

The Recipe for Clean Air

The 1970 Clean Air Act called for the Environmental Protection Agency (EPA) to establish and promulgate primary and secondary national ambient air quality standards to protect health and welfare, and for states and EPA to develop emission control limits for new and existing sources of air pollution. The primary ambient air quality standards, which the states have deadlines to meet, are intended to protect the most sensitive members of the population against any adverse health effects caused by air pollution. They must include a "margin of safety" and are to be set by EPA without regard to the cost of attainment. The welfare-oriented secondary standards are designed to protect soils, crops, forests, materials, visibility, aquatic systems, and other ecological values from any "known or anticipated" adverse effects of air pollution.

EPA established these primary and secondary emission standards for sulfur dioxide (SO_2), nitrogen oxides (NO_x),

and several other pollutants in 1971. Shortly thereafter, states began to develop implementation programs to meet them. EPA also established in 1971 the first New Source Performance Standards (NSPS) restricting SO_2 and other emissions from new fossil-fired utility boilers.[3]

This was the basic framework for air quality improvement called for by the 1970 Clean Air Act, and it had barely begun to operate when Congress made major changes to it in 1977.

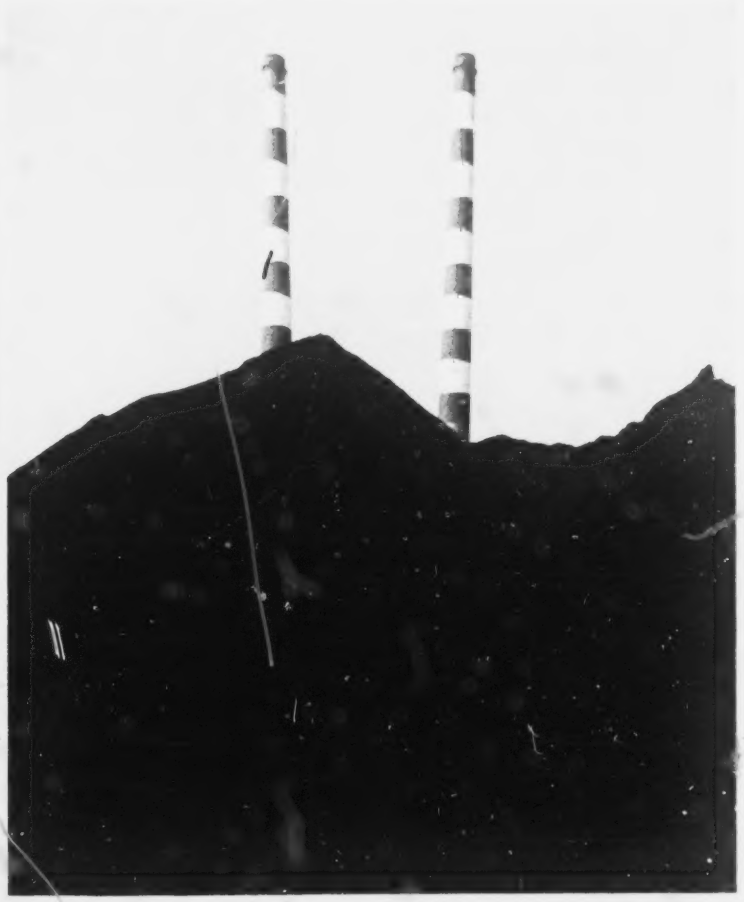
Catalyzed by environmental litigation in the early 1970s, Congress amended the Act in 1977, adding a complex new program to "prevent significant deterioration" of air quality in areas already complying with the ambient air standards mandated in 1970 (see sidebar: The PSD and Visibility Protection Policies), tightening control requirements for new stationary and automotive sources, and authorizing EPA to establish a program to "remedy any existing" and to "prevent any future" manmade impairment of visibility at 158 national parks and wilderness areas. But just a few years following these 1977 Clean Air Act Amendments, it became apparent to federal and state regulators and regulated industries alike that they needed to be simplified.

Acid Rain Takes Center Stage

The quest for Clean Air Act reform began in earnest in 1980. When the Reagan Administration took office in 1981, industry groups were optimistic about the prospects for cutting some of the red tape added to the Clean Air Act through the 1977 amendments. Meanwhile, environmental groups were developing a strategy to strengthen the Act. They seized the acid rain issue as a tactical defensive weapon to resist what they regarded as an imminent industry-led "gutting" of the clean air law. Long-range atmospheric transport of pollutants from the Midwest was alleged as the major cause of acidified lakes in the Northeast and in Canada. Environmentalists sought to amend the Act by having it specifically require a 10-million-ton reduction in annual SO_2 emissions to be accomplished over 10 years in a 31-state area of the eastern United States.

Aided by vigorous Canadian lobbying and an attentive media, acid rain soon became the focus of the clean air debate. In July of 1982, the Senate Environment and Public Works Committee approved an 8-million-ton SO_2 rollback by a 15-1 vote.[4] In the House, a similar proposal was defeated in the Health and Environment Subcommittee. Later, an aggressive environmental lobbying attack on an industry- and Administration-supported bipartisan bill (H.R. 5252) stalled deliberations and eliminated any possibility for final action on Clean Air Act reform in 1982.

The Senate Committee's 1982 acid rain control bill never reached the floor for debate, mainly due to concerns about



The Clean Air Act has allowed for improved air quality while accommodating large increases in fossil fuel use.

The most important question Congress will address is whether additional emission controls are needed to reduce acid deposition.

the electric rate and coal market impacts of a huge SO_2 rollback. Studies by individual utilities suggested rate hikes of 50 percent or more might be needed to comply with the Senate proposal. EPA estimated the annual cost of the bill at $3.5–4.5 billion (1982 dollars).[5] Potential coal production displacement from fuel-switching was estimated by EPA at 100–150 million tons annually. The Senate leadership had little appetite for a bloody floor fight over acid rain controls.

In 1983, acid rain control advocates in the House introduced a bill (H.R. 3400) designed to overcome the political roadblocks faced by earlier acid rain proposals.[6] By forcing 50 of the largest coal-fired powerplants to install flue gas desulfurization equipment (scrubbers), with a portion of the capital costs to be subsidized by a nationwide one mill per kilowatt-hour ($0.001/KWh) fee on fossil-fired power generation, the new House bill was intended to minimize potential electric rate and coal market disruptions. This approach was dealt a setback last May when the bill was defeated by a 10-9 vote in the House Environment Subcommittee. Nonetheless, with over 100 cosponsors in the House, this bill is likely to remain influential in the design of any acid rain control legislation. It would require a total emission reduction of 10 million tons of SO_2 and 4 million tons of NO_x in the 48 contiguous states by 1993. Approximately 6 million tons of SO_2 would be reduced through the top-50 plant scrubber retrofit requirement, which would become effective in 1990.

A 10-million-ton SO_2 rollback bill was approved last March by the Senate Environment and Public Works Committee.[7] The successor to the 1982 Senate bill, the new measure raised the 31-state SO_2 reduction requirement from 8 to 10 million tons, and retained a controversial emission cap provision. This cap would require SO_2 and NO_x emissions from most new sources in the 31-state East to be offset by reductions at existing sources. Such a cap could be very costly after an initial SO_2 rollback had been accomplished, since the rollback would eliminate all low cost emission reduction opportunities: for a new, fully-scrubbed coal-fired powerplant emitting 15,000 tons of SO_2 annually, an emission offset requirement might raise annual operating expenses by as much as $15–30 million annually.

The acid rain control approaches evolving in the House and Senate may be difficult to reconcile. The House seems to favor a 48-state control strategy with forced scrubbing, partly subsidized through a national fee on non-nuclear power production. The Senate bill's 31-state plan has no subsidies, no coal market protections, and no forced scrubbing. Senators from the Northeast and West argue that a national subsidy approach like the House bill would discriminate against their relatively low-polluting states. Southern congressmen are concerned about the industrial growth limitations inherent in acid rain control legislation. Midwesterners are apprehensive about the sharp electric rate impacts of current proposals, and everyone is concerned over the lack of proof that any of this will lead to ecological benefits. Environmentalists' current insistence on a 12-million-ton SO_2 rollback adds further complications, since a rollback this large could be achieved only through massive scrubbing and fuel-switching, with significant adverse impacts on both electric rates and regional coal markets.

Who Pays?

The costs of an acid rain control bill would be determined by the size of the initial emission reduction, the costs of scrubber retrofits as well as increased premiums for low-sulfur coals,

The acid rain control approaches evolving in the House and Senate may be difficult to reconcile.

The prevention-of-significant-deterioration (PSD) and visibility provisions added to the Clean Air Act in 1977 have provoked tremendous controversy and confusion. The PSD program applies to areas with air quality better than that required by the national ambient air quality standards. It consists of a set of arbitrary "increments" of allowable air quality deterioration for sulfur dioxide and particulate matter which are "consumed" by the addition of new source emissions to ambient air quality levels in these areas.

Compliance with PSD requirements can add two or more years to new plant planning and construction schedules. Stripped of its time-consuming air quality monitoring and computer modeling requirements, the heart of the PSD program is the new source review for Best Available Control Technology (BACT). By law, BACT cannot be less stringent than applicable New Source Performance Standards. For coal-fired power plants, EPA's current New Source Performance Standards require 70 to 90 percent SO_2 removal—a *de facto* scrubbing requirement.

Despite recent efforts by industry and state government groups to secure streamlining revisions of the PSD program, such as elimination of most PSD increments, Congress has shown little willingness to depart from the elaborate requirements of this program. PSD reform proposals approved last March by the Senate Environment Committee would give state governments discretion to eliminate some PSD increments—a process states might find difficult if faced with environmental opposition. Proposed Senate changes to PSD also would strengthen the case-by-case new source review, putting pressure on states to require new sources to control emissions to the greatest extent achieved by similar sources in the region.

The new visibility protection program for national parks and wildernesses has been interpreted by EPA to require protection of visibility at so-called "integral vistas" at these areas, or views of distant scenes from within park boundaries. EPA's 1980 visibility regulations allow states to deny PSD permits to plants whose emissions would adversely impact visibility at integral vistas.

Contrary to initial fears that existing powerplants near national parks would be required to install "Best Available Retrofit Technology," EPA's 1980 visibility regulations have not resulted in any such retrofits. A possible "Phase II" visibility protection program addressing sources of regional haze could have more far-reaching and costly consequences, requiring extensive retrofits in areas of the East and West. EPA has not yet decided how to address regional haze problems under the Act's visibility protection mandate for national parks and wilderness areas.

The PSD and visibility protection policies have raised concerns about the ability to site new powerplants and other energy facilities, particularly in coal and oil shale regions of the West. With only a few exceptions, however, the PSD and visibility regulations have not yet prevented individual facilities from siting in chosen locations. This is mainly due to the limited amount of PSD "increment consumption" or air quality deterioration since 1977, which in turn reflects recessionary economic growth and the related slowdown of new plant construction.

There are legitimate concerns about the future impact of the PSD and visibility protection policies on new plant siting and coal conversion. Potential coal conversions in the Northeast and the Gulf Coast may be constrained by PSD requirements. Powerplant siting in the West is especially vulnerable to environmental challenges due to the large number of western national parks, wildernesses, and related "integral vistas." Visibility protection for the West may require states to mandate SO_2 emission control requirements for coal-fired powerplants well in excess of the 70 percent scrubbing removal required for most western low-sulfur coals under EPA's current New Source Performance Standards.

The economics of alternative pollution control strategies can only be assessed on a plant-by-plant basis.

and whether offsets for new source emissions are required. Cost estimates typically range from $4 billion (annualized 1984 dollars) for an 8-million-ton rollback up to $10 billion or more for a 12-million-ton reduction.[8] The costs of SO_2 emission reductions rise rapidly after 5 million tons because of market pressures on low-sulfur coal prices and the higher costs of installing scrubbers on older and smaller powerplants. The reliability of these cost estimates diminishes at the higher reduction levels since it is impossible to predict how fuel supply and other markets would operate under the influence of such a huge emission cutback.

Electric rate increases would be influenced by these same factors and by any national cost-sharing mechanism that might be authorized. Utility industry studies indicate that an 8-million-ton rollback could force individual utility systems to raise their rates by 15 percent, 20 percent, and in some cases 50 percent or more.[9] Proponents of acid rain control legislation point to computer modeling studies claiming that such a rollback could be achieved for statewide average rate increases of just 2 to 4 percent.[10] This disparity reflects very different study approaches: the utility industry estimates are based on plant-by-plant engineering cost estimates for retrofitting scrubbers or switching to lower-sulfur coal, while the statewide averages are estimated with a computer model of utility and coal markets. There are good reasons to question the applicability of such models to the real worlds of utility fuel markets and state rate regulation.[11]

Proposals to spread the costs of SO_2 emission reductions through a national cost-sharing program would not greatly reduce the electric rate impacts of a massive SO_2 rollback. Analyses of the House bill show that its one mill/KWh fee on all fossil-fired generation would offer very modest protection for utilities and their ratepayers. As shown in Table 1, the Office of Technology Assessment found little difference between statewide rate impacts under the House proposal with and without a one mill/KWh cost-sharing formula.

A recent Edison Electric Institute (EEI) study found that utility rate increases per household in Midwestern states receiving the largest disbursements under the House proposal would be reduced by only 25 percent as a result of the one mill/KWh cost-spreading formula.[12] This study also concluded that the one mill/KWh fee may be sufficient to pay for only about one-fifth of the capital, fuel, and maintenance costs of the House bill. Clearly, cost-sharing is no panacea. And due to the sharp regional differences of opinion on the allocation of rollback costs, congressional consensus on a cost-sharing formula may be impossible.

Opponents of the scrubber-based House bill have argued for fuel-switching as a "least-cost" approach to emission reductions. A low-sulfur coal group claims that emission reductions can be achieved cheaply by switching to low-sulfur coal. Their analysis suggests that reliance on low-sulfur coal rather than scrubbers could save utilities and ratepayers more than $1 billion annually.[13]

The economics of alternative pollution control strategies can only be assessed on a plant-by-plant basis. Nonetheless, it is doubtful that there is any general "least-cost" solution to SO_2

Table 1

Electric Rate Impacts from H.R. 3400, Selected States, With and Without 1 Mill/KWh Fee

State	Percent Change With Fee	Percent Change Without Fee
Alabama	2.2-3.1	1.9-2.8
California	1.5	0.0
Florida	2.2-2.8	2.1-2.7
Illinois	3.1-3.6	4.3-4.8
Kentucky	8.6-10.2	12.8-14.3
Missouri	5.7-6.0	9.9-10.2
West Virginia	4.9-5.2	7.0-7.3

Source: Office of Technology Assessment (July 1983)

A solid record of progress has been achieved under the Clean Air Act.

emission reductions. If a large cutback in eastern SO_2 emissions were mandated, market pressures on rail transport rates and low-sulfur coal prices would tend over time to make low-sulfur coal switching costs equal to the costs of flue gas scrubbing for high-sulfur coal.[14]

Figure 1 illustrates the relationship between low-sulfur coal price premiums and scrubbing costs for a typical 500 MW coal-fired unit. In this example, the unit has a choice between scrubbing a medium-sulfur coal (2.8 lbs. SO_2 per million btu) or switching to a low-sulfur coal (1.2 lbs. SO_2 per million btu). In the scrubbing case, the annual cash outlays rise sharply in the initial years due to scrubber construction costs, and then drop to reflect annual operating and maintenance expenses. At a $5 per ton premium, low-sulfur coal would be substantially cheaper than scrubbing. With higher low-sulfur coal premiums, scrubbing becomes more economic.

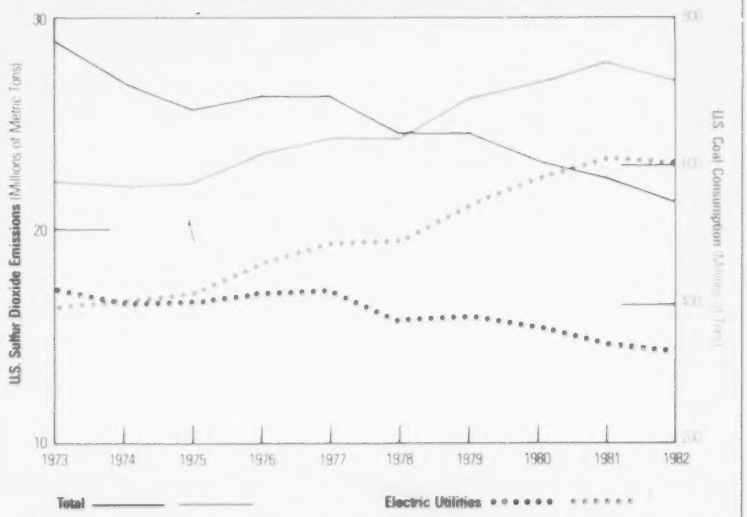
The breakeven low-sulfur coal price premium—the premium which equalizes the cost of removing a ton of SO_2 by scrubbing and fuel-switching—is $10.10 per ton in this example (expressed in 1985 dollars.)[15] For low-sulfur coal premiums greater than $10 per ton, it would be cheaper to reduce a ton of SO_2 by scrubbing than by switching.

Current low-sulfur premiums in eastern coal markets are $2–$4 per ton in the spot market, reflecting depressed market conditions and large excess mining capacity. Under firmer market conditions, a much greater premium would be expected. In 1981, for example, the 15 largest eastern powerplants burning both high-sulfur and low-sulfur coals incurred an average low-sulfur coal premium of $13 per delivered ton.[16] In the EEI study of H.R. 3400, an average low-sulfur coal premium of $18 per ton for contract deliveries was found in a survey of 24 utilities. In 1979, the premium for low-sulfur fuels was the largest single component of U.S. electric utility pollution control costs.[17]

In the East, where low-sulfur coal reserves are relatively limited and confined to thin seams, it is likely that low-sulfur coal producers would seek hefty ad-

A solid record of progress has been achieved under the Clean Air Act. From 1973 to 1982, total emissions of sulfur dioxide dropped by 26 percent, from 28.9 to 21.4 million metric tons per year. (See figure.) Electric utility SO_2 missions declined by 17 percent in this period, from 17.2 to 14.3 million metric tons. These reductions are all the more impressive in light of the huge increases in coal utilization occurring over the 1973–82 period: total coal consumption rose 25 percent, while utility coal use leaped by 53 percent. Simultaneously, broad indicators of urban air quality such as the "Pollutant Standards Index" have shown consistent improvement since the 1970 Clean Air Act was passed. Americans are enjoying measurably cleaner air today than in the early 1970s.

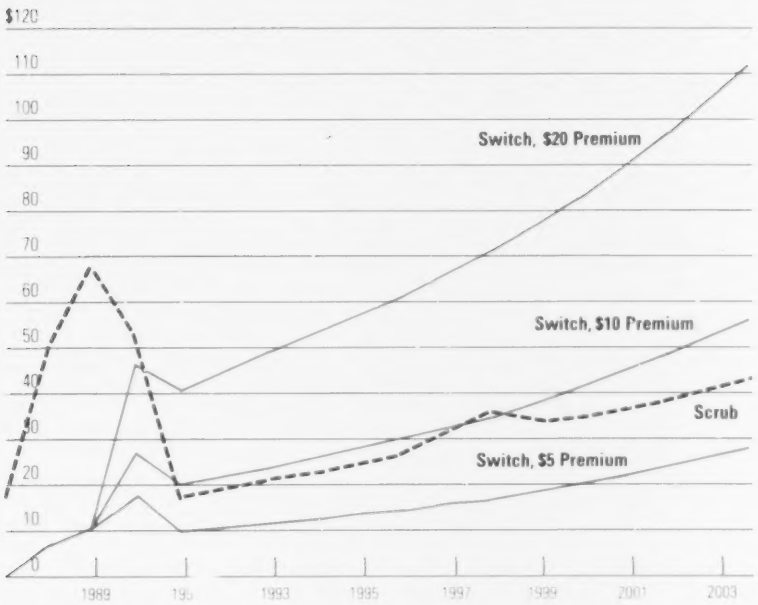
U.S. Coal Consumption versus Sulfur Dioxide Emissions



The vast majority of the country already is in compliance with the ambient air standards for SO_2.

Figure 1

Cost Comparison Low-Sulfur Coal Conversion Versus Scrubbers. Annual Outlays: 500-MW Coal Unit. (Millions of Current Dollars.)



Source: Temple, Barker & Sloane, Inc.

Assumptions

Inflation rate: 6 percent/year for capital and operating and maintenance costs; 8 percent/year for fuel premiums.

Discount rate: 12 percent.

Scrubber costs: $250/KWh capital; $12.50/KWh/year fixed operating and maintenance; 1.6 mills/KWh variable operating and maintenance; capacity and energy penalties 5.5 percent; replacement energy 25 mills/KWh.

Plant heat rate: 10,000 btu/KWh. Coal heat content: 10,000 btu/lb.

Pre-compliance emission rate: 2.8 lbs SO_2/million btu.

Post-compliance emission rate: 1.2 lbs SO_2/million btu (switch to low-sulfur coal); 0.3 lbs SO_2/million btu (scrubber).

ditional price premiums if large SO_2 reductions were mandated. Western low-sulfur coal, already prohibitively expensive in much of the East due to steep rail transport costs, could be even more costly if acid rain controls led to major increases in the demand for low-sulfur coal. Slurry pipelines to carry western coal to midwestern utility markets could reduce delivered coal costs if their capital investments proved reasonable—and if the necessary rights-of-way and water supplies could be obtained. Eastern utilities confronted with emission control decisions would have to judge for themselves where future sulfur premiums, transportation prices, and scrubber retrofit costs would place them in relation to the costs shown on Figure 1.

Who Benefits?

The acid rain phenomenon is popularly regarded as the long-range transport of pollutants from coal-fired powerplants in the Midwest, producing highly acidic rainfall in sensitive areas like the Adirondack Mountains. According to this view, the benefits of reduced rainfall acidity would accrue mainly in the Northeast, while the costs of SO_2 controls would be borne largely in the Midwest. While most of these control costs can be estimated roughly, the benefits of acid rain control are not easily measured.

Start with pH, the measure of rainfall acidity. Current rainfall in the northeastern United States averages 4.2 pH. Researchers at the MIT Energy Lab have estimated that a two-thirds reduction of eastern SO_2 emissions would raise this average to just 4.4 pH.[18] EPA, on the other hand, is looking into evidence that all of the aquatic damages attributed to acid rainfall already may have occurred, and additional damages would be expected only if future SO_2 emissions increased greatly.[19]

Environmentalists stress the cumulative nature of acid deposition and claim that current SO_2 emissions are pushing us to-

We simply don't know if a single lake would benefit from implementation of current acid rain control proposals.

ward a "point of no return" where ecosystem damages become irreversible. However, cumulative acid deposition trends for the eastern United States indicate that a large SO_2 rollback in the 1990s would not significantly reduce cumulative deposition, compared to deposition quantities expected with the current Clean Air Act.[20] Incomplete scientific understanding of the ecological impacts of acid deposition makes it impossible to estimate the benefits from a marginal change in rainfall acidity. We simply don't know if a single lake would benefit from the implementation of current acid rain control proposals.

These uncertainties have led proponents of acid rain control to attempt to redefine the issue. Environmental leaders now claim that SO_2 reductions would yield large benefits in improved visibility and human health protection.[21] The reduction of SO_2 emissions allegedly would prevent thousands of premature deaths annually and would generate billions of dollars each year in visibility benefits. These "visibility benefits" represent what people say, in response to hypothetical questions, they would be willing to pay for improved visibility.

Even if such claims were valid —and they can be rebutted vigorously—they would point only to a possible deficiency in the way the Clean Air Act has been administered, but not to any shortcoming in the Act itself. The national ambient air quality standards are intended to protect health, visibility, and every other environmental value allegedly threatened by current SO_2 emissions. The vast majority of the country already is in compliance with the ambient standards for SO_2.[22] Touting the visibility and health benefits of an "acid rain" control policy may be politically advantageous as a way to convince some Members of Congress that their constituents would benefit from a costly accelerated emission reduction bill. However, it is an argument without merit in light of the existing regulatory authority in the Clean Air Act.

How Much, How Soon?

What emission reductions can be expected under the current Clean Air Act? What reductions have occurred already? How would future emission trends differ if Congress enacted new emission reduction legislation?

In the absence of the Clean Air Act, annual SO_2 emissions would be 10 to 12 million tons greater than they are today.[23] The replacement of older coal-fired powerplants with new ones subject to New Source Performance Standards will result in further emission reductions over time.

Projections by the Electric Power Research Institute (EPRI) indicate a continuous decline in SO_2 emissions over the next 30 years.[24] EPRI concludes that a 10-million-ton SO_2 rollback bill would yield real emission reductions only until the year 2010 or so, when emission totals would equal those expected with the current Clean Air Act. The rollback would produce only a temporary dip in an otherwise declining emission trend. EPRI also finds that reliance on new, clean generating technologies such as atmospheric fluidized bed and low-btu combined cycle coal gasification would produce the fastest possible reductions in emissions after 2000.

A less optimistic picture is drawn by EPA, which claims that SO_2 emissions may increase slightly by 2000, before beginning to taper off gradually in the next century.[25] The sluggishness of EPA's emission trend forecast reflects a conservative assumed rate of retirement of existing plants and some increases in industrial SO_2 emissions. Small industrial coal-fired steam units are not yet subject to emission controls as stringent as the New Source Performance Standards for utility boilers.

The U.S. Department of Energy (DOE) has taken an intermediate position. DOE sees sta-

There simply is no evidence of a crisis from current levels of SO_2 emissions . . .

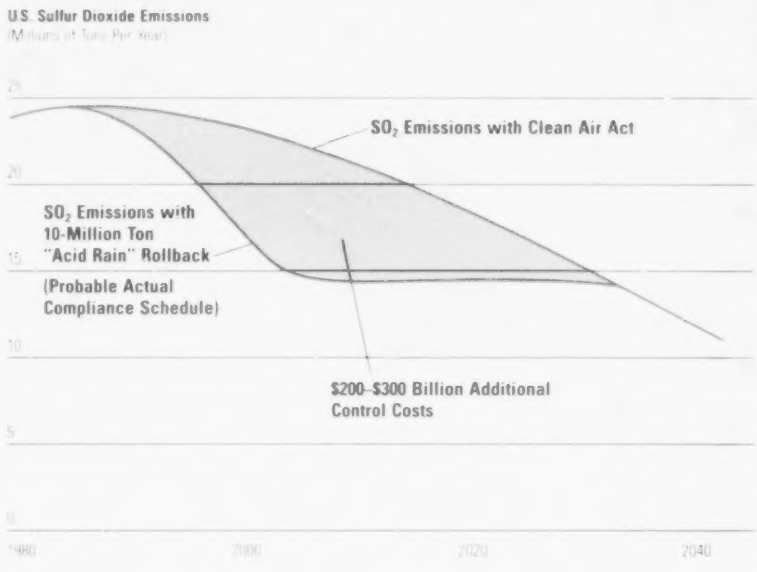
ble SO_2 emissions through 2000, with a decline picking up speed around 2010. Tougher new source emission controls attained through advanced generating technologies could yield a 10-million-ton SO_2 reduction by 2030.[26]

Thus, under the rather pessimistic EPA and DOE forecasts, current SO_2 rollback proposals would produce real reductions in emissions for a period of only 20 to 30 years, with the largest reductions occurring during the middle 10 years (See Figure 2). After another 10 years—around 2010—the difference between the accelerated rollback emission trend and the emission trend under the current Clean Air Act would begin to narrow. Between 2015 and 2030 the two trends would converge. As noted, the impact on rainfall acidity of a 10-million-ton SO_2 reduction may be as little as two-tenths of a point on the pH scale. The net effect of acid rain control legislation therefore may be little more than a 0.2 pH change in average rainfall acidity for a couple of decades.

Is this worth the $200–$300 billion total cost of a 10-million-ton rollback bill?[27] What resources are genuinely at risk if we pursue our current path to clean air? Instead of a crash rollback costing hundreds of billions, should we first pursue a low-cost direct mitigation program for liming acidified lakes? How much is known about the economic side-effects of a massive rollback program on industry, consumers, the elderly? Before rushing to judgment, should we wait for the completion of the 10-year federal National Acid Precipitation Assessment Program? Authorized by Congress in 1980, this intensive inquiry into the causes and effects of acid rain is only now beginning to bear fruit.

Figure 2

Alternate Paths to Clean Air: Sulfur Dioxide Emission Trends Under The Clean Air Act and Proposed "Acid Rain" Control Legislation, 1980–2040



Given the certainty of high costs and the uncertainty of tangible benefits from a crash SO_2 rollback, the critical issue Congress must address is whether the nation would be better off if the $200–$300 billion for proposed acid rain controls were directed instead to more urgent, health related environmental problems, such as hazardous waste clean-up. There simply is no evidence of an imminent ecological crisis from current levels of SO_2 emissions, which will decline dramatically anyway under existing Clean Air Act programs. With limited economic resources available for environmental protection, and in view of our current $25 billion annual commitment to air pollution control, Congress surely could find higher priority environmental uses for the hundreds of billions of dollars at stake here. Surely too, we would be better off if sensible resource allocation questions like these replaced the emotional frenzy of the acid rain debate. EP

NOTES

1. Council on Environmental Quality, *Environmental Quality 1982* (U.S. GPO, 1983), Table A-80.

2. A 1983 Harris poll indicated that 86 percent of respondents wanted the Clean Air Act kept intact or made stronger. *Coal Mining & Processing*, March 1984, p. 17.

3. EPA's Revised 1979 NSPS replaced the 1971 NSPS for new coal-fired boilers which had limited maximum emission rates to 1.2 pounds SO_2 per million btu heat input, and which could be met by the use of low-sulfur coal without scrubbers. The 1979 revision requiring 70 percent to 90 percent reduction of potential SO_2 emissions was based on a 1977 amendment to section 111 of the CAA, requiring a "percent reduction" of potential emissions to be achieved through use of the best technological system of continuous emission reduction.

4. S.3041 (97th Cong., 2nd Sess.)

5. See ICF Incorporated, "Analysis of a Senate Emission Reduction Bill (S.3041)" (Prepared for U.S. EPA, February 1983).

6. H.R. 3400 (98th Cong., 1st Sess.).

7. S.768 (98th Cong., 1st Sess.).

8. See ICF, note 5 above, and "Developing the Options for Emissions Control," *EPRI Journal*, November 1983, p. 50.

9. National Economic Research Associates, Inc., "Report on the Results from the Edison Electric Institute Study of the Impacts of the Senate Committee Bill on Acid Rain Legislation (S.768)" (June 20, 1983), Table 1.

10. See ICF Incorporated, note 5 above.

11. See MIT Energy Laboratory, *The ICF, Inc. Coal and Electric Utilities Model: An Analysis and Evaluation* (MIT Ef. 81-015, Revised October 1981), Vol. I.

12. Temple, Barker & Sloane, Inc., "Executive Summary to Evaluation of H.R. 3400." (Prepared for Edison Electric Institute, January 1984), p. 10.

13. See Paul R. Portney, "Making Sensible Environmental Policy: The Case of Acid Rain," (Prepared on behalf of the Alliance for Clean Energy, and based upon a September 1983 study for the Alliance by ICF Incorporated).

14. See Larry Parker and Duane Thompson, "Acid Rain Legislation and the Future of the Eastern Low Sulfur Coal Industry" (Congressional Research Service, April 6, 1984).

15. If a precontrol emission rate of 4.0 pounds of SO_2 per million btu had been assumed, the low-sulfur coal price premium breakeven would be $13 per ton (instead of $10 per ton at the 2.8 pound SO_2 rate). At this level, the cost per ton of SO_2 removed would be approximately $600 for scrubbing or switching, instead of the $865 cost per ton of SO_2 with an initial emission rate of 2.8 lbs. of SO_2 per million btu.

16. E. M. Irisko, "Clean Air Act at the Crossroads," *Coal Mining & Processing*, July 1982. Data are for December 1981 from FERC Form 423.

17. Temple, Barker & Sloane, Inc., "Environmental Regulations and the Electric Utility Industry, An Integrated Overview." (Prepared for U.S. EPA, December 1982), p. I-17.

18. Fay, J., Golomb, D., and Gruhl, J., "Controlling Acid Rain," (MIT Energy Lab Report 83-004, April 1983), Table 2.

19. "Statement of William D. Ruckelshaus Before the Committee on Environment and Public Works, United States Senate," February 2, 1984, pp. 8–9.

20. See Kay H. Jones, "Acid Deposition Precursors," *The Environmental Forum* (Environmental Law Institute, January 1984), pp. 11–13. Jones analyzed cumulative hydrogen ion deposition in a 15-state area of the northeastern U.S. for the period 1950–2000 under "business as usual" and "Mitchell bill" (10-million-ton SO_2 rollback) scenarios, and found that: "... the accumulated deposition potential resulting from the Mitchell bill provision is not significant, representing only a maximum of 4.6 percent of the total deposition which will have occurred between 1950 and the year 2000 for this region." Since most of the emission reductions from acid rain controls are expected to occur after 2000, Jones's analysis understates the potential cumulative deposition reduction. See the discussion of emission trend forecasts at the end of this article.

21. See "Testimony of Richard E. Ayres, Natural Resources Defense Council, Before the Senate Committee on Environment and Public Works," February 10, 1984, p. 6.

22. See Report of the National Commission on Air Quality, "To Breathe Clean Air" (March 1981) p. 3.4–5 (in 1980 18 counties and 70 portions of counties were in violation of the primary NAAQS for SO_2; 5 counties and 21 portions of counties were in violation of the secondary NAAQS for SO_2).

23. Council on Environmental Quality, note 1 above, Table A-59 (9 million tons of SO_2 reduced in 1979). See also *EPRI Journal*, note 8 above, p. 50.

24. See *EPRI Journal*, note 8 above, p. 50.

25. ICF Incorporated, note 5 above, p. S-2.

26. "Statement of Jan Mares, Assistant Secretary for Policy, Safety and Environment, U.S. Department of Energy, Before the Senate Subcommittee on Energy Research and Development," March 12, 1984, pp. 9–10.

27. Temple, Barker & Sloane, Inc., note 17 above, estimated the cost of H.R. 3400 at $265 billion current dollars through 2008.

INTERLOCKING TECHNOLOGIES OF ELECTRIC TRANSPORTATION DEVICES

People are getting around in less time and with more ease than ever, and to a large extent electricity is making it possible.

By Richard J. Arnold

Richard Arnold is a Washington, D.C. freelance writer.

Consider the elevator. In 1854 Elisha Graves Otis, who may well have been the Lee Iacocca of his era, personally demonstrated his automatic safety mechanism on a freight elevator. He did this by riding the platform high in the air and ordering the rope cut. The mechanism held, of course, and so did the technology. This demonstration of the first passenger elevator came to full fruition in 1889 when the first electrically-operated passenger elevator was installed in the Demarest Building in New York City. With the advent of this first electric people mover the face of urban geography was forever changed.

At one time considered rare and wondrous, today electric transportation devices are as familiar as sidewalks. In some instances they *are* sidewalks. People are getting around a lot faster these days, and to a very significant degree electricity is making it possible. All manner of electric transportation devices move man both vertically and horizontally in mere fractions of the time and energy expended a century ago.

The history of electric transportation in the United States has been a series of newly developed and ultimately interlocking technologies which, although sometimes abandoned, have more frequently been recycled and embellished. From magnetism and the electric motor, to the battery and beyond, the technological chain often doubles back upon itself, but it is seldom broken. Discarded technologies are largely recalled and metamorphosed into something new, something more efficient, or even something once again transitional.

Electric Cars

Take the electric car. In 1912 over 34,000 people did. For a brief while the electric car dominated the personal transportation world, winning out over the declining horse and bicycle, and even over the ascending steam and internal combustion carriages. It was, unfortunately, a technology that could not keep pace with its competitors.

Presently more than 2,000 electric cars are on the road in the United States, although drivers may have to wait another decade or so before they'll be able to test drive electric cars at local showrooms. Two examples of utilities experimenting with EVs are the Detroit Edison Company and the Long Island Lighting Company (LILCO). Detroit Edison has 24 Volkswagen Rabbits powered solely by batteries, and company commuters have logged over 250,000 miles on these cars since this program began in June of 1981. LILCO, with a substantial effort to improve vehicle reliability and maintenance efficiency, has a fleet of 26 vehicles used for inter-office mail delivery, meter reading, plant security control, commuting, and field inspections. According to Edward C.

The first battery-powered electric car, built under the direction of Thomas Edison.

. . . the electric car has provided pivotal technology for many vehicles in use today.

Essig, LILCO's electric car program coordinator, the company's cars' mileage tally is now approaching 200,000.

"An ideal vehicle would provide us with a range of 50 to 75 miles per day throughout the year," Essig believes. But, he added, "lead-acid batteries are affected by cold weather, so we get about 50 percent less range in the winter."

"We're very conscious of the routes we send the vehicles out on," Essig continued. "We pretty much know the vehicle is going to complete the task assigned to it."

At its inception, many things went right with the electric car. It was smooth-running, efficient, clean, and infinitely dependable. For these and other reasons, the electric car was the favored transportation of many. Women in particular enjoyed the freedom accorded by the elimination of crank starters. Doctors prized them for their dependability in even the coldest weather.

What went wrong with the electric car was its inability to transcend its battery, speed, and mileage limitations. These factors of themselves may not have posed any problem for the electric car; however, the invention of the electric starter for internal combustion engines did. At this point, technology passed the electric car by in a blur of motion. The very affordable Model T, or "tin lizzie," initiated mass production. Pneumatic tires were invented that made rugged terrains traversable. Large oil reserves were discovered in the United States. Each of these factors contrived to make the countryside far too alluring. Gas vehicles could extend their range indefinitely by storing or carrying supplemental fuel. By comparison, the early electrics had an approximate range of 20 miles per charge when they first arrived —acceptable in light of the poor road conditions of the time. But they traveled at low speeds of 20 mph or less and required 8–12 hours to recharge batteries. Although range and speed were increased considerably as time went on, many people continued to judge electric cars by their early performance. By the same token, rural residents had no electricity so this vehicle had no appeal to them.

Detroit Edison electric-powered Volkswagen Rabbit.

Detroit Edison

Pivotal Technology

Despite its unrealized potential, the electric car has provided pivotal technology for many vehicles in use today. Completely enclosed bodies, controls positioned on the left, steering wheels, and the substitution of a drive shaft for a chain drive were all features originally incorporated into the electric car several years prior to their adoption by gasoline cars. Later, the lead-acid battery, which powered the first electric cars, was expanded upon—its plates were made thicker and it was improved so that it could be recharged 200–400 times. The results of this mutation are evidenced in today's golf carts. Here we see a battery so uniquely suited to its job that it is predominant in the field. In 1980 there were over 300,000 electric golf carts in use in the

Mark Bartlett

In the United States alone there are currently 100,000 forklifts in use.

United States. This same technology is readily converted to airport passenger or baggage carriers, industrial vehicles or even flatbed trucks.

One of the most inventive transformations from liability to boon was the development of the forklift in the 1930s. These industrial vehicles harnessed the great weight of the battery series necessary to power the electric car and employed it to provide the ballast and power needed to lift and to haul large and heavy loads. A later switch from resistance controllers to solid-state controllers for purposes of speed variation enabled this machine to compete with its internal combustion counterpart in handling loads up to 10,000 pounds. In the United States alone there are currently 100,000 electric forklifts in use.

There are many other electric transportation devices in use today that highlight reliability rather than speed and that have their roots in the electric car technology. Among these are the various electric wheelchairs and other vehicles available for the handicapped and lightweight electric trucks and vans. Electric wheelchairs and similar vehicles, which provide a speed range of approximately 1.9–3.8 mph greatly enhance their users' independence with their lightweight and highly maneuverable designs. By the same token, the electric van, developed in the early 1900s, was, and is, an ideal use for electric power. Its low maintenance and almost insignificant "down time" have made it the paragon of service reliability. In 1971 the U.S. Postal Service began tests to study the feasibility of using the electric van. The results of these tests were astonishing. Out of 1800 vehicle-days of service, only 33 of those were in down time. A comparison of fuel costs demonstrated a 3.5¢ per mile advantage over comparable gas-powered cars, which use almost 6¢ of gas per mile. While all routes could not be served by this type of vehicle, a significant number can—and are. It was estimated in 1981 that out of a possible 103,144 mail routes, 30,000 could be served by using present technology. None of this is news to the United Kingdom, however, which has employed electric vans for more than 40 years to transport milk, eggs, and perishables. At a cost of approximately 5¢ per mile there are over 50,000 of these so-called "milk floats" currently operating in that country. Easy to service and a model of reliability, their life expectancy is equally admirable—15 to 20 years.

Trolleys and Interurbans

While the electric car was being developed, trolleys were filling the transportational gaps between horse-drawn carriages and railroads. Although the automobile later rendered it obsolete, the trolley, which ran in the city, and the interurban, which ran between cities, provided several technological breakthroughs. In 1888 the first electrified streetcar line (a 12-mile track) opened in Richmond, Virginia. This was the brain-child of Frank Sprague, who eventually developed the multiple-unit control device which enabled the operation of a string of self-propelled cars through a single set of controls. While this innovation was not used specifically on the trolley lines—which generally ran single cars—it later became very important to the larger railways that ran passenger trains of two or more cars.

As the market for electricity increased, so did the distance over which it had to be transmitted. Trolley and interurban service extended farther into rural areas, and thus higher voltages were necessary for efficient electrical transmission. In this way the trolleys occasioned the invention of substation converters to change AC power to DC for distance runs. The top wire of the trolley lines carried AC current generated by the main power station to the various substations, which converted this

The sociological implications of the trolley are legion.

power to DC through their respective rotary converters. The DC power was then transmitted to the car motors. DC current was preferred for trolley and interurban use because it provided better torque and speed control. In time, portable substations were invented to add to the flexibility of these systems. It was also Sprague who invented the first protected third rail that is, in other forms, still in use in many subway systems today.

The sociological implications of the trolley are legion. They helped foster the growth of cities, multiplied land values, and transported workers to jobs at almost twice their walking speed of 3.1 mph. Perhaps most importantly, however, they paved the way for electric trains.

Electric Trains

To avoid smoke and noise problems in a tunnel section of track, the Baltimore and Ohio Railroad electrified a small stretch of its line in 1895, thereby heralding the electrification of U.S. trains. In the years between 1900 and 1938, a few mainline electrifications followed along with the deployment of a number of metropolitan terminals and suburban services. This trend was brought to a rather abrupt halt with the advent of the diesel, which supplanted the need to electrify rails while offering superior efficiency to steam. The post-World War II era brought a rapid extension of electrification to Europe. By 1972 a significant percentage of total route miles in foreign countries had been electrified (Sweden—62 percent; Italy—59 percent; Japan—45 percent). The United States, however, had accumulated less than 1 percent.

Electric trains are generally considered to be the most economical and efficient means of railroad operation, provided electricity is available and traffic density justifies the heavy capital cost. They are capable of drawing upon central power plant resources, which is especially effective for starting heavy loads and climbing steep grades. Additionally, electric trains have low maintenance costs and down time. Aesthetically they are quieter, and generate neither smoke nor fumes. There are limitations, however. One major one is that speed capabilities are dictated by the existing track curvatures and grades. Also, electric trains require high costs to revamp old stations to meet their needs as well as for changes in signal systems.

By mid-twentieth century, foreign countries had discovered that because it is a more complex mechanism, the diesel train ultimately costs more to buy and maintain than the electric train. In this same interval, the United States seemed unwilling to commit itself to the large capital costs of power distribution and feed-wire systems.

Trolley car of the Lynn and Boston Railroad.

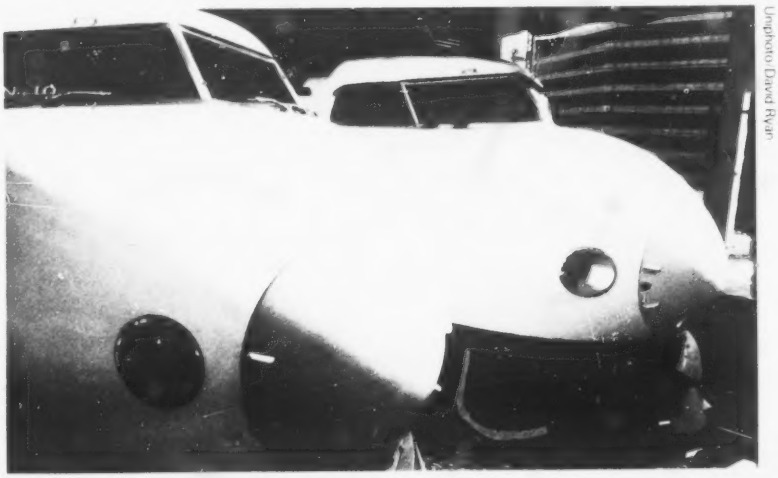
Smithsonian Institution

Frank Sprague (1857-1933), father of electric traction.

. . . over 50 percent of the world's railway traffic is carried electrically.

This reluctance would in time preclude the "bullet train" advances electrification would afford countries such as Japan, whose Tokaido Line is in the forefront of train lines. With capabilities of 150 mph (carrying a 12–16 car load) and a general average speed of 103 mph, the Tokaido clearly embodies the concept of electric trains achieving their full potential. The line is electrified with a 25,000 volt wire and boasts a Tokyo to Osaka run—320 miles with two stops—in three hours and six minutes. Lest this be considered an electric flash in the pan, it is important to note that bullet trains have successfully been running in Japan for over 20 years.

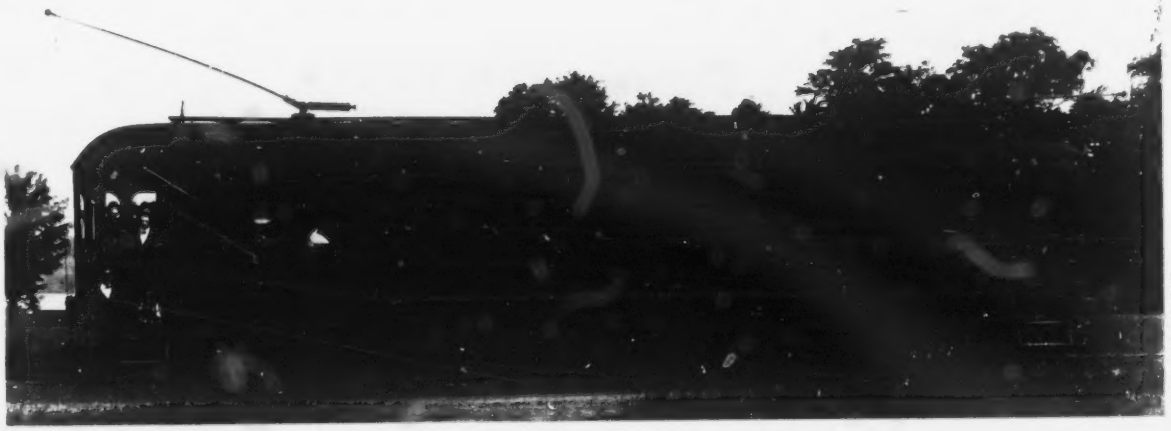
It is perhaps for this reason that some consider that the most significant potential for electricity in the transportation sector of the United States is electrification of the railroads. If one excludes the United States, over 50 percent of the world's railway traffic is carried electrically. Recently the United States has taken a closer look at this technology. Under present consideration are intercity bullet lines which would connect Los Angeles and San Diego; Houston and Dallas; and Tampa, Orlando, and Miami.



Unphoto/David Ryan

People Movers

How does the technology of the "people movers" fit into the scheme of things? Rather well. Although these devices seemed relegated to a limbo-like status somewhere between trains and cars, they have been around as long as both, and, in some incarnations, have outlived many of their contemporaries. By opening the way to higher buildings, and ultimately skyscrapers, the elevator played a decisive role in city development. Later, electricity paved the way for other technological improvements in this invention. Push-button controls arrived in 1894, and in



Smithsonian Institution

Top, Japanese bullet train—the concept of electric trains achieving their full potential. Bottom, early electric interurban car.

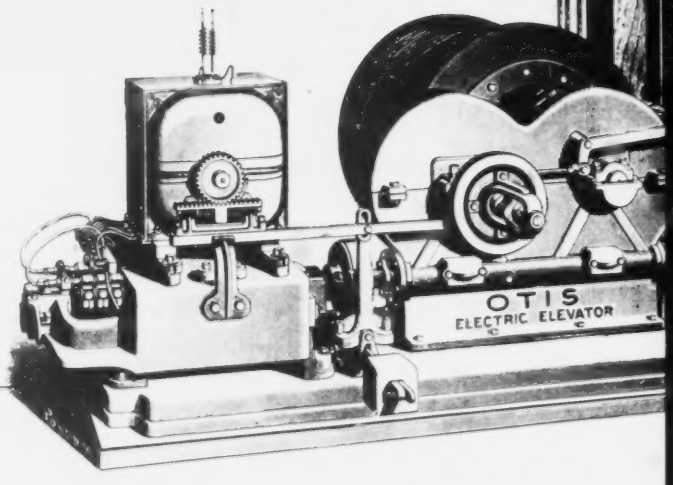
1895 a hoisting apparatus was installed that applied power to the pulley at the top of the shaft thereby making possible taller shafts and greater speeds.

Practically all modern elevators, whether used for basic freight and passenger operations in buildings or in ships, dams, and even rocket launchers are electrically propelled. Observation cars, transparent walled elevators rising on the outside of buildings and towers, have become popular in more recent years. In addition to the beauty of their futuristic designs, the glass-enclosed cabs afford passengers a scenic view as they ride.

The escalator appeared just two years after the first electric elevator ascended New York's Demarest Building. The original consisted of a belt inclined at an angle of 25 degrees, attached cleats for passengers, and a stationary handrail. It gained notoriety during the 1900 Paris Exposition with an adjusted incline to 30 degrees and including a moving handrail. Modern escalators are capable of travelling 120 feet per minute, and the larger ones are able to handle 6,000 passengers per hour. Moving ramps, an offshoot of escalator technology, are horizontal people movers with an incline range of 0 to 15 degrees. Both have made themselves indispensible through their application in airports, subways, buildings, and other mass pedestrian areas.

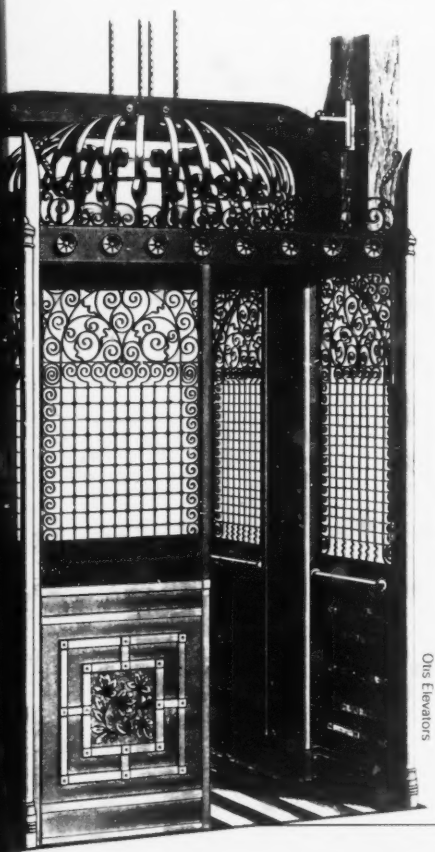
Even before the electric trolley, the steam-powered elevated line, another people mover, was

Mark Borchelt



Above, contemporary glass-enclosed observation cars with escalators in foreground. Right, early Otis electric elevator.

used for local transit in urban areas. These trains usually operate above street levels on a trestle. The first electric "L" was Chicago's West Side Metropolitan Elevated Railroad, which made its appearance in 1895. Another Chicago line employed Frank Sprague's multiple-unit control system for its cars in 1897. Eventually the popularity of the "L's" dwindled largely due to their noise pollution, contributions to traffic congestion, and aesthetic shortcomings. While the elevated's heir, the monorail, has eliminated two of these drawbacks, no successful system has yet been built for a central business district. Of the monorail systems currently in operation, the "Airtrans" system at the Dallas-Ft. Worth International Airport is perhaps the most extensive and is fully automated.



Otis Elevators

Subways are probably the best adapted for carrying large numbers of people over short and medium distances as well as into and through the central business district. For these reasons they are still being built despite mounting costs and engineering problems. The first, built in London in 1862, consisted of about four miles of track connecting principal railroad terminals. Electricity was added in 1890. Other cities followed suit and within a few years hundreds of miles of subways were completed generally using the "cut and cover" method of trenching streets and then covering them over. In the interim, they have transcended the faults that plagued the elevated trains while simultaneously contributing to rising land values. In today's subways, modern escalators and elevators provide easy access, automatic fare systems speed passenger transactions, and electric-powered-car trains generate higher rates of acceleration and increase overall speeds. In this way they have become responsible for taking over the collective duties of trolleys, interurbans, monorails, and, to a lesser extent, the "L" and the automobile for transporting millions of commuters safely and efficiently into, through, and out of our nation's cities—more so than any other system.

The Future

What's in the wings for electric mass transit? As with most electric transportation devices, its future is steeped in the past. Borrowing on a technique for the induction motor, patented by Nicola Tesla in 1888, modern designers are looking at linear induction vehicles—a form of transportation without wheels that was suggested in 1895. Linear induction vehicles (LIVs) travel on a wave of magnetic force, and, more importantly, their motors have no moving parts. The underside of a LIV is lined with electro-magnets that produce a magnetic wave that pushes the vehicle forward. A top speed of 155 mph has been recorded and a 300 mph speed is anticipated.

The impact of the electric transportation device is, in retrospect, a force with which to be reckoned. It is as powerful as it is unpredictable. Originally viewed by many as a secondary selling point for the successful commercial generation of electricity during the late 1800s, the electric transportation device has transcended that role to become the mover and shaper of cities in the late 1900s. So completely has it now infused itself into man's lifestyle that convenience has translated into necessity. Though it is difficult to imagine that the electric transportation device could play a more integral part in contemporary society, even now the next link in the technological chain is being forged.

ELECTRICITY. IT'S THE POWER OF CHOICE.

Industry marketing program promotes demand-side solutions to regain 'sense of community' between electric utilities and their customers.

By Robb Deigh

Robb Deigh is a Washington, D.C., writer.

From a tiny station that provided energy for about 50 flickering lights in Manhattan over a century ago, the electric utility industry has become an indispensable part of the way all Americans live and work. To make this contribution, the industry has overcome many technical problems to refine the art of producing, transmitting, and distributing electricity—safely and reliably.

But in recent years, a profound change in the sense of community that traditionally characterized the relationship between local utilities and the customers they serve has taken place. There is now a feeling of alienation and disconnection by customers that began with the "Shock of Seventy-Three" as the industry moved to help reduce the United States' dependence on foreign oil and keep customers' electric bills as low as possible.

Industry executives have long been concerned over the growing split between their companies and the people they serve. The most frequent dialogue that exists in many cases, they say, is typically complaint-oriented at best and often hostile. This year, America's investor-owned electric utility companies and the Edison Electric Institute (EEI) have begun a multi-faceted marketing program to bring them closer to their 63 million customers.

"The industry has been talking to customers about our needs and wants more than theirs—solutions on our side of the meter," says Thomas D. Morron, EEI's Vice President for Customer Services and Marketing. "For example, we may need more generating capacity to meet consumer needs. But it is clear that customers regard this as our problem and they don't want to hear about it."

One of the keys to changing the public's attitudes, Morron stresses, is to promote a fundamental change in the way customers regard electricity itself. "Every time they turn on a switch, they are making a purchase decision," he says. "They should approach this purchase decision in much the same way as selecting items at a supermarket."

The Program Objective

After three years of study, countless industry-wide meetings and discussions, and gallons of strong coffee, EEI is confident that it has developed an effective marketing program that will broadly address the industry's objective of developing demand-side solutions to the problem of creating a better equilibrium between customer energy needs and wants and the industry's ability to produce that energy.

The program, known by its theme, *Electricity. It's the Power of Choice.*, began in September 1980. EEI's Communication, Customer and Industrial Relations Policy Committee directed the Customer Services and Marketing Executive Advisory Committee to study whether a national marketing plan could be developed to establish or reinforce positive perceptions of the value of the work electricity performs and the strength of the industry that provides it, to

RESEARCH & DEVELOPMENT PROJECT

EXTERNAL COMMUNICATION PROJECT

- ADVERTISING ACTIVITY
- PROMOTIONAL SUPPORT ACTIVITY
- PUBLICITY ACTIVITY
- OUTREACH ACTIVITY

INTERNAL COMMUNICATION PROJECT

- INTRODUCTORY ACTIVITY
- CONTINUING ACTIVITY

TRADE ALLY & AFFILIATE

SPECIAL AUDIENCE PROJECT

- LEGISLATIVE & REGULATORY ACTIVITY
- CONSUMER ORGANIZATION ACTIVITY
- BUILDER ACTIVITY

TRAINING & ORGANIZATION PROJECT

- TRAINING ACTIVITY
- ORGANIZATION ACTIVITY

. . . changing the load shape that a utility must serve can reduce operating costs.

promote a sense of customer/industry partnership in solving the problems caused by rising costs and diminishing supplies, and to improve profitability.

The program gained further momentum when the Advisory Committee created a marketing task force, led by John Russell, Vice-President of Long Island Lighting Company. In the spring of 1981, Russell's task force appointed a consortium of outside firms to conduct the actual study research and write a report on their findings. The three firms were Benton & Bowles (marketing); Manning, Selvage & Lee (public relations); and Harbridge House (management consultants).

Next came extensive workshop discussions with member-company executives in regional meetings, thorough analysis of information collected by the consortium, and nationwide field testing of its conclusions. The consortium then proposed two strategies in the marketing plan to reestablish closer working relations between the electric companies and their customers:

- *The Value/Cost Appeal:* reminding customers of the everyday tasks that electricity performs, the incomparable service it provides, and the good value it represents at a reasonable cost.
- *The Cost Control/Customer Options Appeal:* showing customers how they can control the size of their monthly electric bills by the amount of electricity they use.

One of the biggest problems faced by the task force was constructing a program that would function equally well in all parts of the country. "The energy crisis had imposed quite different problems on different utilities," Russell says. "A solution for one company often created a problem for another. The development of a single national program that would be practical and useful to all was not easy."

A Sense of Community

In September 1982, the Policy Committee enthusiastically endorsed the marketing study for its ability to bring to center stage the needs and wants of customers and the abilities of the industry in light of changes that have taken place within the past two decades.

The marketing plan, which has already shown progress in bringing the two sides together, involves the participation of industry employees and their customers at all levels. It's ultimate goal will be to regain that sense of "community" the electric industry has had with its customers from its inception until recent years.

The *Power of Choice* program includes six major projects: Research and Development, Internal Communication, Special Audiences, External Communication, Training and Organization, and Trade Ally and Affiliate.

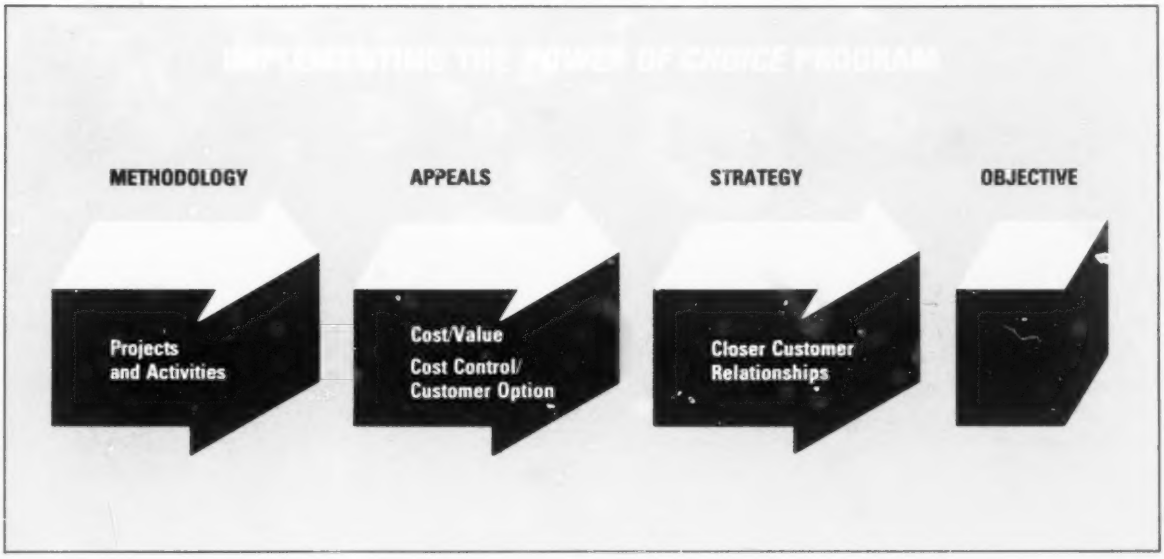
The Research and Development Project

The *Power of Choice* program most fully addresses the need for demand-side management in the research and development project. One of its primary tasks is to identify the kinds of control options member companies feel would be most useful to them and their customers.

EEI invited the Electric Power Research Institute (EPRI) to help in this project. EPRI has plunged into the work and delivered a three-volume series—*Demand-Side Management—Overview of Key Issues, Demand-Side Management—Evaluation of Alternatives,* and *Demand-Side Management—Technology Alternatives and Marketing Methods*—designed to help member companies arrive at a better understanding of the potential of various demand-side management options to improve load factor and, eventually, to improve company profitability.

While demand-side management is not a panacea for all problems facing the utility industry, it does provide additional alternatives to the industry for meeting the challenges of the future. For utilities with strong load growth, load management and strategic conservation can provide an effective means to reduce or postpone construction of new generating facilities. For other utilities, electrification and deliberate increases in the market share of energy intensive users can improve the utility load characteristics and optimize the reserve margin. Aside from these rather obvious examples, changing the load shape that a utility must serve can reduce operating costs. Changes in the

. . . full participation throughout the ranks of member companies is a crucial part of **Power of Choice** *activities.*



load shape can permit adjustments in plant loadings, thus increasing the use of more efficient plants and permitting the use of more domestically abundant and less expensive energy sources.

In the residential sector, cost control/customer options give the customer capability to control monthly electric bills. Many electric customers who had become accustomed to stable prices up to the early 1970s have seen dramatic increases in their electric bills. In many parts of the country, these upward price trends are expected to continue, albeit at a somewhat reduced rate. Demand-side alternatives —in particular, cost control/customer options—give customers a positive signal that the utility is concerned about high electric bills and is providing its customers with the means to control future expenditures for electricity.

Most often, member companies already have the insight, analysis skills, data, and other tools to assess, for example, the effects of new equipment or to measure the utility's load profile. But the information may not be in the hands of marketing executives. There may be too much information organized in a format that makes it inaccessible to them.

The research and development project will address this issue through the training of outside consultants and the involvement of appropriately skilled company executives.

The project has four goals:

- to develop ways to determine company-specific needs,
- to apply those methods at the local level,
- to determine which needs can be met with available technologies, and
- to develop new technologies wherever possible on a cost-effective basis.

Those involved in the *Power of Choice* program say the research and development aspect is the key to balancing customers' needs and industry abilities. Accordingly, it will be given the highest priority.

The Internal Communication Project

Esprit de corps and full participation throughout the ranks of member companies is a crucial part of *Power of Choice* activities. As a cooperative effort, it can only be as effective as the dedication that employees at all levels place in the program.

"In the early 1970s the electric utility industry's internal marketing communication network collapsed along with all the other marketing components," says Morron. "We have begun the rebuilding process."

The industry must present itself as smaller, less anonymous, less political, and more personal.

With a recognition of the need for a team effort, all members will be kept informed of the latest developments in the *Power of Choice* program and what they can do to make it work best in their areas. Communication will take place at three levels: senior management, functional management, and general employee. At the senior management level, activities will keep key executives up-to-date and encourage their continuing support. Functional management communication will ensure a full flow of operational information, and general employee projects will make certain that this important group is an active part of the team.

Members will be informed of program activities through seminars, regional meetings, periodic information reports, and regular committee meetings.

Once the program is at a full gallop, EEI hopes to send out a number of "circuit riders"—a group of regional program representatives—who will spend their time visiting participating companies to keep them abreast of new developments. The circuit riders will also keep Washington headquarters informed about what is working on the local level and what is not, as voiced by member companies.

The Special Audience Project

A very important ingredient would be missing from the *Power of Choice* program if "special audiences" were not included. And, the most special audience of all is the "average customer."

If any customer can really be considered "average," research shows that customer would probably be:

- a man or woman living in a single-family home in Ohio or Arizona,
- with 1.7 children,
- purchasing 8,539 kilowatt hours annually at 5.4 cents apiece.

Also, average customers and their average neighbors, coast to coast, contribute about $35 billion a year to the revenues of the electric utility industry. They *are* the *Power of Choice* marketing audience.

But there are other special audiences too. Legislative and regulatory audiences must understand the concepts and goals of the program so as not to misinterpret its purpose. As planners were putting together the program, they met with a number of government officials (Congressmen, staffs, and regulators) to explore their reactions to proposed activities. Reaction was very favorable. Key officials at the national and state levels will be kept informed about the marketing program on a periodic basis through informational materials and briefings.

New home builders are another special group that will ensure the program's success. According to the National Association of Home Builders, there will be more than 7 million new home starts in the next five years. Builders will be encouraged to install energy-efficient systems and appliances and load-shifting and cost-control mechanical devices wherever they are available and cost effective. A heat pump exhibit is available for their use in promoting that type of equipment. Various channels of communication have been set up to keep them aware of developments.

The *Power of Choice* program is also paying particular attention to a very special audience—organized consumer groups whose membership numbers in the tens of millions. EEI has established a National Consumer Advisory Panel, made up of senior executives of some of those national groups.

EEI has met with panel members to tell them what is planned during the program. They, in turn, have told program leaders whether those plans appropriately serve the interests of their constituents.

"What this is," says Morron, "is public participation at the national level, and it is working. In the meetings we have had, there have been no adversarial debates. There has been reasoned discussion. In all cases, the end results have been constructive; the program has been improved. We think this is a shining example of the fact that getting together is a better way."

The External Communication Project

Sixty-three million people are tough to reach. But you reach them one at a time by showing a genuine concern for their problems, which, of course, are the industry's problems as well.

This is the goal of the external communication project, an "all-

The goal of outreach activities is to reunite the industry and its customers . . .

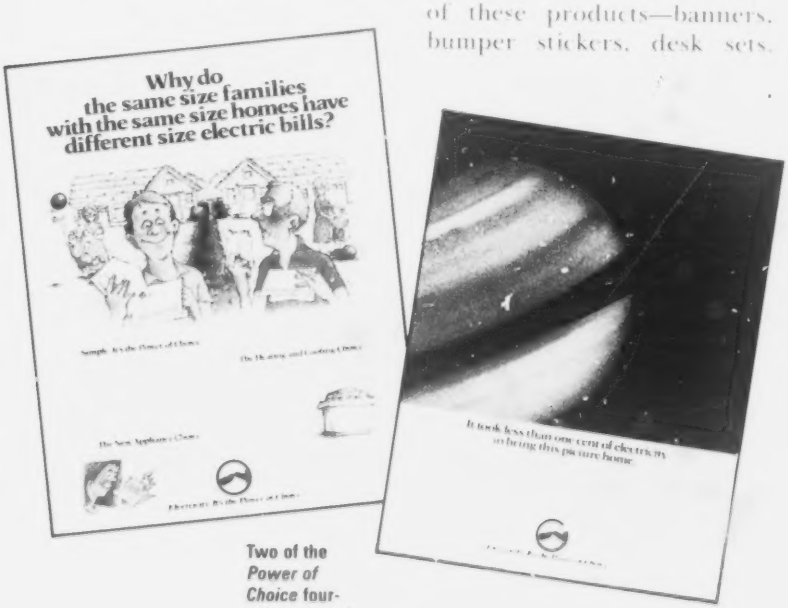
hands-on-deck" approach to rebuilding the industry's credibility as a caring member of the community. The industry must present itself as smaller, less anonymous, less political, and more personal. It is here that *Power of Choice* is designed less as a national program than as a national federation of local programs—not the voice of an industry, but the voice of a friend and neighbor. Activities will include advertising, promotion, publicity, and outreach.

Already a number of advertisements have appeared, each with the distinctive new logo—a finger on the light switch—to remind people that using electricity is a purchase decision.

Four-color print ads have been run in leading national magazines, including *Newsweek, Reader's Digest, Time, People, U.S. News & World Report, TV Guide, Modern Maturity,* and *Southern Living.* For example, one magazine ad asks the question, "Why do the same size families with the same size homes have different size electric bills?" And the answer: "Simple, it's the Power of Choice." The text goes on to tell readers that wise use of electricity and careful selection of appliances can mean lower bills.

Television commercials have aired more than 200 times this year on the three major networks. Programs include ABC's *Good Morning America, Nightline,* and *World News Tonight.* On NBC and CBS as well, programs include nearly all of the major news programs.

Promotional activities will make use of published materials, special events, a mobile exhibit program, and products imprinted with the *Power of Choice* logo. A catalog of more than 100 of these products—banners, bumper stickers, desk sets, employee jackets, lapel pins, and other items—is now available to participating companies for their local use.


Why do
the same size families
with the same size homes have
different size electric bills?
It took less than one cent of electricity
to bring this picture home.

Two of the *Power of Choice* four-color print ads.

Tony Anthony, EEI's Director of Public Information, and his staff are working to develop a number of stories about the program for national and local publication. Also, plans are in the making to allow a continuing flow of informational materials and news about the program both for national and—through participating companies—local media. This program is designed to develop closer ties with key media executives, editors, and reporters.

The outreach portion is the newest and, perhaps, the least developed of all the external communications activities. But in terms of reaching the customer as a friend and neighbor, EEI's President, William McCollam, Jr., calls it "the center of gravity."

The goal of outreach activities is to reunite the industry and its customers so they once again will work together to solve mutual problems instead of approaching each other as adversaries.

One of the most innovative aspects of outreach activities being considered is a network of nationally promoted neighborhood "electric stores." All constructed to standard *Power of Choice* motifs, the stores will offer personal help to customers to help them solve their energy problems. They will bring the industry to the customer instead of waiting for the customer to come to the industry.

. . . marketing can be used to shape load as well as to stimulate it.

Also, an *Outreach Compendium*, a chronicle of about 60 outstanding activities already initiated by EEI members across the country, is available as a guide to other companies. It will review the problems, outline proven solutions, and evaluate the results.

A *Public Participation Manual* is also available. This book, put together jointly by EEI's Consumer Affairs and Environmental Committees, explores general and specific areas of customer involvement in industry decisions and then reports on actual member company experience with particular activities.

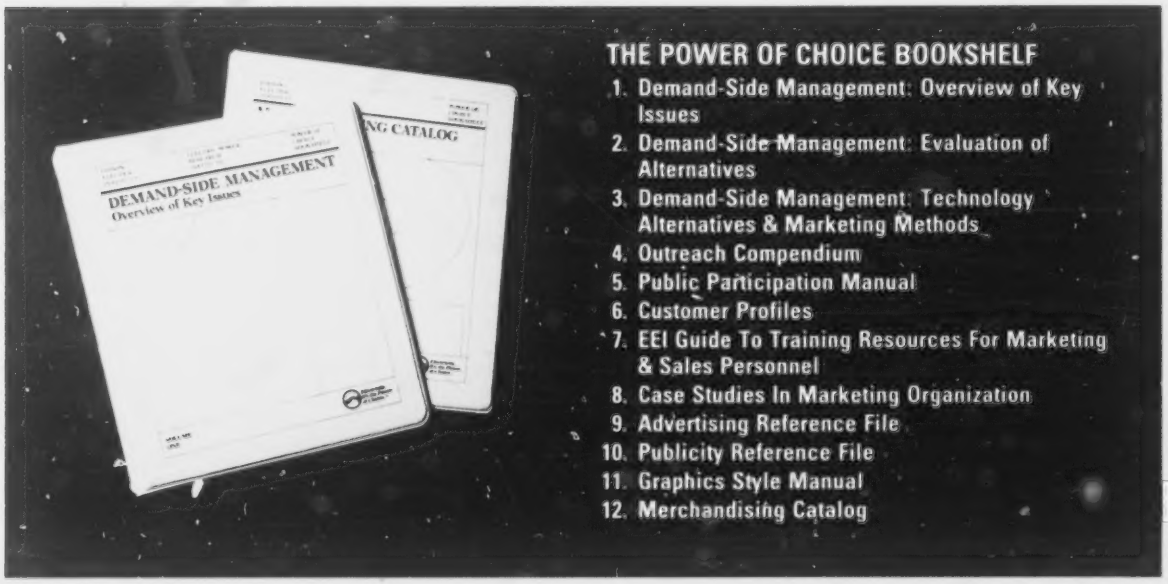
EEI is developing a book called *Customer Profiles* to help members learn more about the people that make up their local publics. It will take existing statistical and demographic studies and translate them into human insights to provide a deeper understanding of the lifestyles and problems of groups in the United States.

The Training and Organization Project

Many of the member companies are going to need help in reestablishing marketing organizations that were dismantled in the early 1970s when additional sales in many companies created more problems than they solved and it was thought that marketing was no longer a needed function. Utilities have now come to realize that marketing can be used to shape load as well as to stimulate it, and that with this potential, it can become the industry's most valuable tool in developing demand-side solutions to its load problems.

When many companies deactivated their marketing departments in the early 1970s, they simultaneously dismissed or transferred their marketing personnel. The result now is that implementation of the national marketing program in many cases will make it necessary for participating companies to rebuild their marketing departments and train new people to staff them.

It is a relatively easy matter to place an additional box on a corporate organization chart. It is much more difficult to train qualified people to perform the function the box calls for. The level of professional sophistication needed by marketing personnel in the electric utility industry is high. The job of persuading customers to modify their energy use habits in such a way as to significantly effect company load curves is not a job for a novice. It takes someone who, among other things, is part engineer, part salesman, part customer, part philosopher, and


DEMAND-SIDE MANAGEMENT
Overview of Key Issues
NG CATALOG
THE POWER OF CHOICE BOOKSHELF
1. Demand-Side Management: Overview of Key Issues
2. Demand-Side Management: Evaluation of Alternatives
3. Demand-Side Management: Technology Alternatives & Marketing Methods
4. Outreach Compendium
5. Public Participation Manual
6. Customer Profiles
7. EEI Guide To Training Resources For Marketing & Sales Personnel
8. Case Studies In Marketing Organization
9. Advertising Reference File
10. Publicity Reference File
11. Graphics Style Manual
12. Merchandising Catalog
Ed Castle

. . . the issue of marketing organization must be addressed.

part sociologist. Ideally, it takes someone who has a lifetime of schooling and experience. That the ideal is not available in large numbers is clear, which simply emphasizes the point that the training, or retraining, process is essential.

Under the utility organizational structures prevalent in the 1960s, the exercise of effective coordination and control over the various marketing activities—advertising, public relations, customer services, consumer affairs, conservation—was greatly facilitated by the fact that most of them were part of a single marketing organization and reported to the same marketing head within the company.

As a result of the disbanding of marketing activities in the 1970s, it is not uncommon today to find that the chief operating officer of a utility, or even the CEO, represents the first common reporting point for the various marketing related activities. Frequently, for example, customer services, advertising, rates, and conservation program directors all report to separate vice presidents, who, in turn, sometimes via executive vice presidents, report to the utility president.

If utility management is seriously committed to implementing the *Power of Choice* program, then the issue of marketing organization must be addressed. EEI will assist member companies in doing so by developing and assisting them in implementing a number of alternative organizational proposals to regain effective coordination of the various marketing activities.

The *Power of Choice Bookshelf*, a twelve-volume set of reference manuals, has been developed and will be available to member companies to assist them in implementing the training and organization project as well as other parts of the program. The entire set includes:

- the three *Demand-Side Management* books,
- the *Outreach Compendium*,
- the *Public Participation Manual*,
- the *Customer Profiles* book,
- the training manual,
- the organization manual,
- the advertising reference file for use at the local level,
- the publicity reference file,
- a graphic style manual with guidelines on how to use the *Power of Choice* logo and other program artwork, and
- the merchandising catalog of promotional materials.

The Trade Ally and Affiliate Project

Power of Choice is not a proprietary program. As all projects emphasize, it is a team effort in the full sense of the term. Municipal, cooperative, and investor-owned utilities are all welcome to participate.

And what better way to demonstrate to customers the program's dedication to the cost-control/customer-option appeal than to have manufacturers and retailers promote the sale of more efficient home appliances?

This project is designed to attract the participation of the innovators in energy-saving appliances—companies like Westinghouse, General Electric, Whirlpool, Lennox, and others—in much the same way as they participated in the *Live Better Electrically* marketing program. EEI hopes that these types of manufacturers will have a strong showing in the *Power of Choice* program.

Putting It All Together

Each of the six major *Power of Choice* projects has been designed specifically to address the needs of local members in playing their important role in the overall national effort. Each project holds the potential for virtually hundreds of day-to-day activities in community, company, and industry relations; energy saving; product innovation; media liaison; consumerism; and overall individual achievement. The accomplishments these activities will make are restricted only by the imagination and dedication of participants in putting it all together to make it work. ⇄

ELECTRICITY SALES AND THE BUSINESS CYCLE

This article was prepared by Michael L. Hays, President of Editorial Consultants, Incorporated, of McLean, Virginia, with technical assistance from Bruce G. Humphrey, Director, and Clara Gordon, Program Manager, for Edison Electric Institute's Energy Modeling & Economic Research Department.

In 1982, for the first time in nearly 40 years, the electric utility industry in the United States generated less electricity than it had in the prior year. Consumption declined from 2,150.7 billion kilowatt-hours (KWh) in 1981 to 2,098.3 billion KWh in 1982. At the same time, the economy experienced a severe cyclical downturn. As this business cycle continued into the recovery phase, electricity sales increased in 1983 and continue to show strong growth in 1984. But many questions remain unanswered. Among them, do electricity sales shadow the business cycle? What does this most recent cycle foretell about future business cycles and electricity demand?

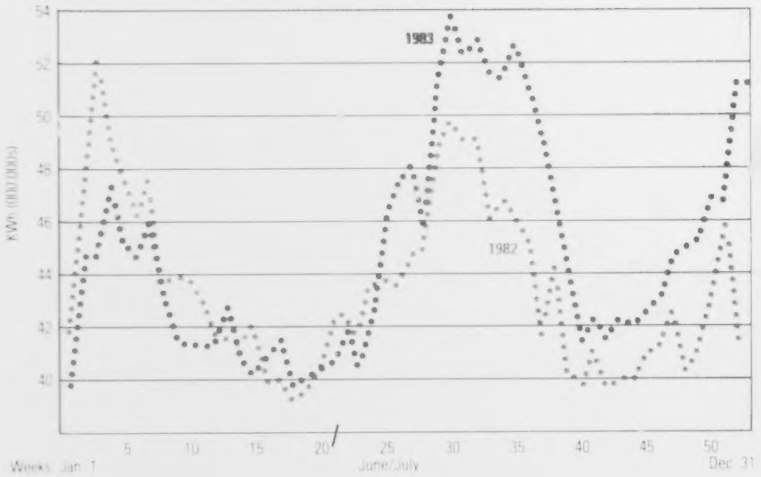
Edison Electric Institute (EEI) data shows that electricity output (net generation, purchases from industries, and imports) and sales through mid-1983 were generally lower than they had been during the corresponding period in 1982. For instance, the index comparing weekly KWh output data for the same week in both years provided negative readings for 19 of the first 26 weeks of 1983, even though economic indexes showed that the recovery had begun at the end of 1982. (See Figure 1.)

This disparity between 1982 and 1983 output and sales figures suggested that electricity consumption was not shadowing the business cycle. By contrast, sales had actualy increased in all past recessions but one. (See Table 1.) The exception resulted from the 1973/74 oil embargo and its increase in energy prices.

To explore what happened, EEI asked Data Resources, Incorporated, to examine the effect of the business cycle on electricity consumption, with particular attention to sales to the individual consuming sectors. This work has been extended and updated by EEI's Energy Modeling and Economic Research Department. The

Figure 1

Year-over-Previous-Year Electric Output



What Do the Indicators Reveal—or Conceal?

Perhaps the most widely accepted measure of the nation's economy is the Department of Commerce's monthly Index of Coincident Indicators, published in its *Business Conditions*

Table 1

Economic & Electricity Indicators (Percent Change from Previous Year)

Year	Index of Coincident Indicators	Industrial Production Index	Total Electricity Sales to Ultimate Customers
1954	−6.7	−5.3	+6.9
1958	−7.6	−6.5	+2.0
1961	−1.0	+0.8	+5.5
1970	−2.0	−3.0	+6.4
1974	−1.4	−0.4	−0.1
1975	−8.1	−8.9	+1.9
1980	−3.6	−3.5	+2.0
1982	−6.6	−8.2	−2.4

Sources: *Business Conditions Digest*, January 1984, p.102; Federal Reserve Board, March 13, 1984
Statistical Yearbook, Edison Electric Institute, (Selected issues)

Digest. This index reflects the condition of the nation's economy on the basis of four sets of data: 1) total non-agricultural employment reported by the Bureau of Labor Statistics, 2) total industrial production reported by the Federal Reserve Board, 3) total personal income less transfer payments (in $1972) as reported by the Bureau of Economic Analysis, and 4) manufacturing and trade sales (in $1972) as reported by several agencies.

The Index of Industrial Production is the index used by the Federal Reserve Board to measure industrial production and, as a component of the Index of Coincident Indicators, closely shadows it. This index, based on data from 235 industries, is a measure of the physical output of factories, mines, and electric and gas utilities as a percentage of production of a base period (currently 1967).

Both the Index of Coincident Indicators and the Index of Industrial Production are often used in comparing economic activity in one period with that of another. Month-to-previous-month comparisons provide a ready indicator of the direction of the economy. Both indexes show that the national economy declined from the third quarter of 1981 through the fourth quarter of 1982. (See Figure 2.)

EEI collects and reports data on KWh output weekly, although this information does not distinguish among consumers. EEI also collects and reports data quarterly on sales of electricity to four sectors: residential, commercial, industrial, and other—a sector including street lighting, other public authorities, and electrified railways.

Output and sales data cannot be compared directly with one another because of transmission losses. Moreover, sales data lags behind output data because of the billing cycle, which varies among utilities and often includes sales from other periods. However, the movements in output and sales data are generally similar over time.

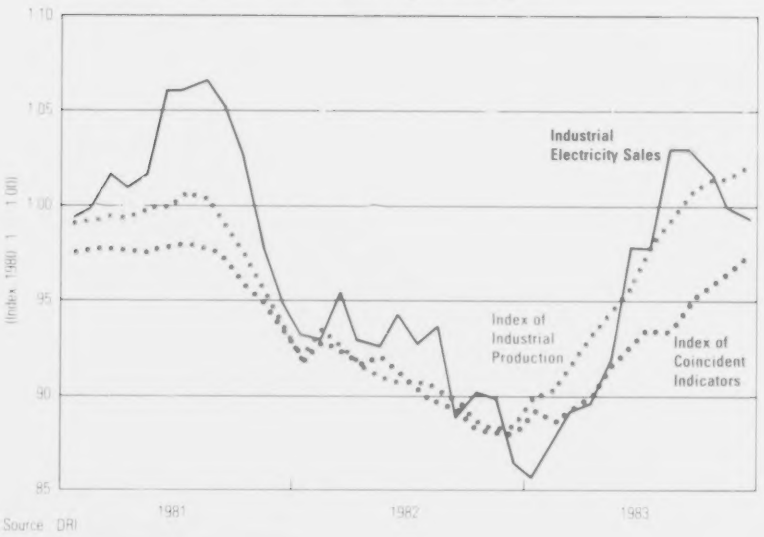
But output and sales data are imperfect indicators of the real condition of the electricity market at any given time because output and sales data reflect, and thus are distorted by, seasonal factors—weather, daylight, and holidays—and economic conditions. These factors not only affect consumption largely independently of one another, but also affect consumption by the residential, commercial, and industrial sectors in different ways.

Consumption by the residential and commercial sectors is far more affected by weather than by the amount of daylight and the occurrence of holidays. Space cooling in summer and space heating in winter account for the large seasonal sales to both sectors. Obviously, a relatively cool summer or warm winter can substantially reduce sales during these periods.

Consumption by the residential and commercial sectors is much less affected by the business cycle than by the vagaries of weather. Regardless of the economy, people try to maintain the comfort of their residences and continue to use their appliances in habitual ways. Likewise, businesses must maintain heating, cooling, and lighting in order to support sales of inventory and services. The business cycle has some influence on consumption

Figure 2

Industrial Production and Electricity Consumption



Source: DRI

in these sectors, although it is difficult to detect and measure, for housing and non-residential construction are cyclical and directly affect the number of consumers.

In contrast, consumption by the industrial sector is largely unaffected by seasonal factors, mainly because industry makes relatively little use of electricity for space cooling or heating. Consumption varies as industry matches production to economic conditions, although some minimal level of production must often be maintained for technical reasons. Seasonally adjusted sales data confirms that industrial sales, far more than residential and commercial sales, are greatly affected by the business cycle as measured by the Index of Coincident Indicators. (See Figure 3.)

Typically, output and sales data from one period are compared with similar data from a like period in the prior year. This period-over-like-prior-period comparison provides some information on the relative condition of the current market. And this comparison is thought to overcome the seasonal and economic distortions on output and sales data from one period to the next.

However, period-over-like-prior-period comparisons have distortions of their own. The weather of the reference period may have been unusual and have had unusual effects on electricity consumption by the residential and commercial sectors. Likewise, the level of economic activity in the reference period may have been unusual, in which case, consumption by the industrial sector would also be unusual. Moreover, the size and relative share of electricity consumption by the residential, commercial, and industrial sectors change over time.

These comparisons may accurately indicate growth in electricity consumption, however, when growth in all sectors is strong and steady over a relatively long period of time. Such growth can overcome the vagaries of weather and the fluctuations of the business cycle. But when growth is more moderate and more variable, these comparisons may not provide entirely reliable information on the relative condition of electricity consumption in a given period.

Unusual weather in the last six months of 1982 and first few months of 1983 and the recession throughout 1982 greatly depressed electricity consumption. Consumption was so far below the prior year's levels that, even when it began to increase as the economy revived, it did not reach and sustain levels of the prior year's consumption until mid-1983. Thus, while economic indexes showed that the economy was improving, EEI indexes comparing electricity data on consumption in early 1983 with that in early 1982 showed negative readings in electricity output.

Data which later became available reveals that sales to the industrial sector had indeed begun to increase when the economy began to recover. (See

Figure 3

Seasonally Adjusted Monthly Electricity Sales versus the Index of Coincident Indicators

Figure 2; the four- to six-weeks' lag probably represents the lag in the billing cycle.)

How Do Trends in Sector Size and Share Affect Sales?

The disparity between actual performance during the recovery and some traditional industry indexes of performance reflects the interaction of long-term growth trends and unusual short-term circumstances. These long-term trends reflect changes in major sectors of the electricity market.

Total electricity sales to end users have more than tripled since 1960, from 683.2 billion KWh then to 2,098.3 billion KWh in 1982, down from 2,150.7 billion KWh in 1981. As total sales of electricity have grown, so the sales to the three major sectors of the electricity market have also grown. However, their rates of growth have varied, changing the pattern of their shares of electricity sales to major sectors.

Electricity sales to the residential sector grew steadily between 1960 and 1980, from 196.4 billion KWh to 734.4 KWh, an increase greater than that in any other sector. During this 20-year period, residential sales increased from 29.9 percent to 35.8 percent of the sales in the three major sectors. The growth of electricity sales to this sector is largely attributable to the sustained growth in the housing and appliance markets that has characterized the post-war period.

Sales to the commercial sector increased dramatically between 1960 and 1980, from 114.8 billion KWh to 524.1 billion KWh, the largest sectoral percentage increase in this period. The share of commercial sales increased from 17.5 percent to 25.5 percent of sales in the three major sectors. The growth of sales to this sector reflects the enormous growth of urban areas with ever larger office buildings and merchandising complexes.

Sales to the industrial sector increased more gradually between 1960 and 1980, somewhat more than doubling from 344.8 billion KWh to 793.8 billion KWh. During this period, the share of industrial sales declined from 52.5 percent to 38.7 percent of sales in the three major sectors. Moreover, sales to the industrial sector have momentarily dipped several times since 1960.

Despite continuing growth in electricity sales, the average rate of annual growth has declined from a rate of 7.3 percent between 1960 and 1973 to 3.2 percent between 1973 and 1980. These different rates of growth, when combined with the seasonal and economic factors affecting electricity sales in the three major sectors, mean that total sales may be more cyclical

in the future than they have been in the past.

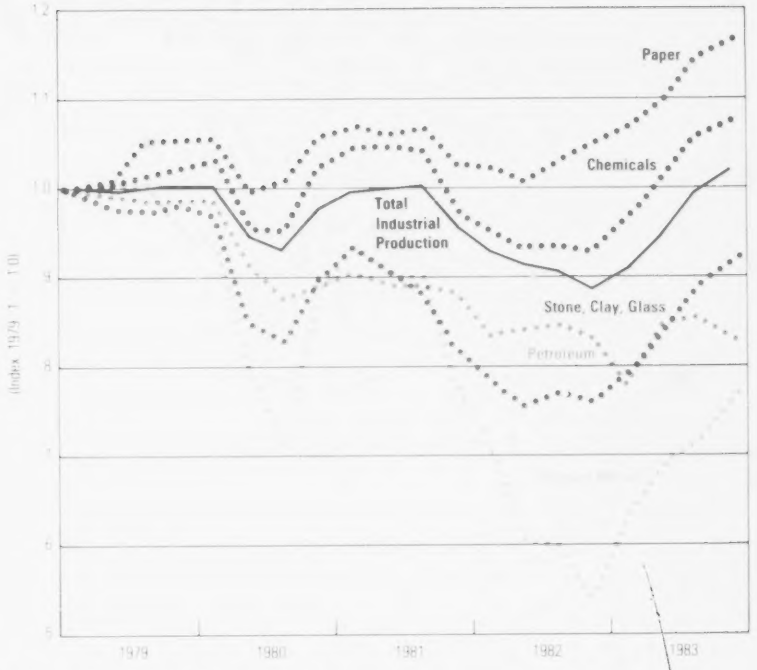
Until the recent recession, rates of growth and the size of sector shares in electricity sales ensured that short-term adverse weather or economic factors were not likely to greatly affect the direction of total annual electricity consumption. Growth in the residential and commercial sectors was so large that sales to these sectors could offset temporarily lower sales to the more cyclical industrial sector; total annual sales continued to rise. Even when unusual weather reduced the level of sales to consumers in the residential and commercial sectors, the effects were offset by increased numbers of these consumers; sales for the year increased over sales for the prior year.

However, present rates of growth and the relative size of sector shares can no longer protect total annual sales from the effects of unusual seasonal or economic circumstances. Modest growth in the residential and commercial sectors of the electricity market can no longer offset the sizable effects of sustained unusual weather. Moreover, because the market shares of these sectors are now much larger than they were, unusual weather for a prolonged period can have an enormous effect on total annual sales.

Even reduced electricity sales to the industrial sector, despite its modest growth and smaller market share, can adversely affect total annual sales because the industrial sector can reduce its purchases of electricity far more sharply than can the other sectors. If a recession reduces sales to the industrial sector over any length of time, the effect can be large enough to decrease total annual sales below prior levels.

Figure 4

Industrial Production Indexes



Source: DRI based on Federal Reserve Board Indexes

Do Business Cycles Affect Sales to Some Industries More than to Others?

The industrial sector is not only very sensitive to fluctuations in the business cycle, but also quite diverse in its patterns of electricity consumption. Some industries are far larger or more electric-intensive than others. Thus, if some of the largest consumers of electricity are more affected than others during a recession, their reduced level of electricity consumption can greatly decrease sales to the industrial sector and increase the likelihood of lower total annual sales. These conditions seem to have occurred during the recent recession.

One way to measure the effect of the business cycle on electricity sales to the industrial sector is to compare an output-weighted measure of production, the Index of Industrial Production,

Table 2

Major Electricity Intensive Industries

	Percent Share of Industrial Production	Percent Share of Electricity Sales to Industrials	Percent Decline in Production '81 Peak '82–'83 Trough	Percent Increase in Production '82–'83 Trough December 1983
Primary Metals	5.0	21.5	−45.4	+43.9
Chemicals	6.2	17.2	−12.9	+15.1
Paper & Allied Products	2.9	6.8	−4.4	+12.7
Stone, Clay, & Glass	1.8	3.9	−18.8	+21.1
Petroleum Refining	3.0	4.2	−16.1	+4.2
Total Industrial Production	18.9	53.6	−12.4	+15.8

Source: DRI, based on Federal Reserve Board Indexes
Note: These production indexes are illustrated in Figure 4

with an electricity-weighted measure. The electricity-weighted measure is derived by multiplying the individual industry production index by industry shares of electricity sales.

The effect of the recent recession on electricity to the industrial sector is pronounced. For only the second time in nearly 30 years, the electricity-weighted measure of production was lower than the output-weighted measure. However, while the electricity-weighted index was 6.7 percent below the Index of Industrial Production during the last quarter of 1982, the gap had narrowed by almost half, to 3.8 percent, by the end of 1983. Indications are that sales to the industrial sector have resumed vigorous growth.

Five of the largest consumers of electricity in the industrial sector are primary metal industries; chemicals; paper and allied products; petroleum refining; and the stone, clay, and glass industry. These five manufacturing industries have modestly increased their share of electricity sales in the industrial sector, from 52.2 percent in 1972 to 53.6 percent in 1981. The production levels of these five industries, which accounted for only 19 percent of industrial output but over half the electricity sales to the industrial sector, can have a great effect on electricity sales to that sector.

During the recent recession, production by these industries decreased sharply. In fact, their performance was a clear indication of the impending decrease in electricity sales to the industrial sector. Production levels for these industries began to drop in the first quarter of 1981, but production levels for all industries did not begin to drop until the beginning of the third quarter. Except for the paper industry, production by these five industries decreased far more severely than the 12.4 percent decrease of the industrial sector taken as a whole. (See Table 2.) However, all but the petroleum refining industry shadowed the economic indexes very closely, and all showed improvement when the economy did. By the end of 1983, these electric-intensive industries showed strong signs of recovery, although not all had regained 1981 levels of production. (See Figure 4.)

What Do Business Cycles Mean for Electricity Sales?

Long-term trends in energy and electricity sales; changes in sector size and relative share of electricity sales; and the effects of weather, seasonality, and economics mean that the positive margin of growth in electricity sales to individual sectors can no longer give assurance of continuous period-over-like-prior-period growth in total electricity output or sales. Because industrial production is so sensitive to the condition of the economy and because several large industrial consumers of electricity are so responsive to economic fluctuations, business cycles are likely to influence electricity sales more than ever before. EP

STATISTICAL REVIEW

ENERGY OUTLOOK

Since 1976, the Energy Information Administration of the U.S. Department of Energy has provided projections of overall domestic energy production, supplies, and prices in its *Annual Energy Outlook*. This year's report, *Annual Energy Outlook 1983*, published in May, provides yearly projections through 1995 for the consumption and supply of energy by fuel and end-use sector based upon several possible scenarios. These scenarios are principally built around alternative forecasts (middle, low, and high) of world oil prices. Following is a summary of the principal economic assumptions and energy forecasts for the middle price scenario.

DOE/EIA 1983 Economic/Energy Indicators and Average Annual Percent Growth Rate

	1983	1983-90	1990-95
Economic & Energy Assumptions			
Real GNP (Billions of $1983)	3,313	3.3	2.2
GNP Implicit Price Deflator (1972 = 100)	216.4	5.5	6.7
World Oil Price $1983/barrel	29.4	3.2	6.6
Energy Indicators			
Energy Consumption (Quads)	70.5	2.1	1.1
End-Use Consumption (Quads)	52.8	1.7	0.4
Electricity Sales (BKWh)	2149	3.5	2.8
Energy Prices			
Electricity Residential ($1983/MBTU)	19.0	0.4	0.6
Natural Gas Residential ($1983/MBTU)	5.8	3.5	7.7
Average Price of Coal ($1983/MBTU)	1.8	1.5	2.2
Refiner's Acquisition Cost of Crude Oil ($1983/barrel)	29.4	3.2	6.6

Basic Forecast Assumptions

- Real GNP is forecast to grow briskly over the 1983-1985 period at a 4 percent per year rate, fueled by a 6.3 percent per year growth in manufacturing and leading to a 4.1 percent per year growth in real disposable income. These growth rates moderate over the long-term.
- The current outlook is for a slight decline in the average world real ($1983) price of oil to $26 per barrel in 1986, and then for a gradual return to the 1980 level of about $40 per barrel by the early 1990s.
- Total energy consumption is projected to increase by 2.1 percent per year in the 1983-1990 period and 1.1 percent annually from 1990 to 1995.
- End-use consumption is projected to increase by 1.7 percent per year in the 1983-1990 period and 0.4 percent annually from 1990 to 1995.

Fuel and Power

- During the forecast period, electricity consumption is projected to rise faster than GNP and about three times faster than total end-use energy consumption. Efficiency in end-use applications and the projected improvement in the price of electricity relative to other energy forms contribute to electricity's improved position.
- Total generating capacity reaches 813.1 gigawatts (GW) in 1995, up from 657.0 GW in 1983. No new starts for nuclear power are projected during the forecast period; new gas turbine and internal combustion capacity additions are scheduled to start in 1991, while new coal additions start in 1993.
- Consumption of refined petroleum products increases by 1.5 percent annually to about 33.3 quadrillion BTU's (quads) in 1990, and 1.0 percent annually from 1990 to 1995. Total imports of crude oil, including that placed in the Strategic Petroleum Reserve, and refined products

DOE/EIA 1983 and Projected Energy and End-Use Consumption

	1983	1990	2000
Energy Consumption (Quads)			
Refined Petroleum Products—Total	30.0	33.3	35.0
Imports—Refined Petroleum Products	10.5	14.3	16.4
Natural Gas—Total	17.4	18.3	17.4
Imports—Natural Gas	1.1	1.3	1.7
Coal	15.8	20.1	22.9
Nuclear Power	3.2	6.3	7.0
Hydro/Other Electricity Imports	4.0	3.7	3.7
Total Domestic Consumption	70.5	81.7	86.1
End-Use Consumption (Quads)			
Residential—Total	8.7	9.2	9.1
Electricity	2.6	3.0	3.4
Commercial—Total	5.6	7.1	7.2
Electricity	2.1	2.8	3.2
Industrial—Total	19.6	2.9	23.7
Electricity	2.7	3.5	4.2
Transportation	19.0	20.5	20.7
Total End Use Consumption	52.8	59.6	60.7
Electricity Total	7.3	9.4	10.8

Note: Numbers may not add to totals due to rounding.

increase from 4.99 million barrels per day (MBD) in 1983 to 6.73 MBD by 1990 and 7.74 MBD by 1995.

- Rapid increases in natural gas prices upon partial decontrol in 1985 are no longer expected. Natural gas consumption increases from 17.4 quads in 1983 to 18.3 quads in 1990, but returns to the 1983 level by 1995.
- The outlook for coal consumption is influenced considerably by the Clean Air Act. U.S. coal production is forecast to rise by an average of 4.2 percent annually from 1983 to 1990, then slow to 2.7 percent per year from 1990 to 1995. Coal is forecast to become the major domestically produced energy source by the late 1980s, contributing 36 percent to U.S. energy production by 1995, compared to 28 percent in 1983.

Consumption

- The commercial sector is projected to experience the largest increase in energy consumption in the 1983-1990 period at 3.4 percent per year. Growth in electricity consumption accounts for most of this growth.
- In the residential sector, a projected decline in energy use per household cancels increases in the number of households. Energy consumption increases by 0.8 percent annually to 1990 but decreases by an average 0.3 percent each year from 1990 to 1995.
- Industrial energy consumption is projected to grow at about 2.3 percent per year between 1983 and 1990 and 0.68 percent per year from 1990 to 1995. The economic recovery assumed in these projections translates directly into higher demand by the energy-intensive industries: basic metals, chemicals, stone, clay and glass, paper, and food.

Oil Disruption

- A hypothetical disruption that assumes world oil availability is cut by 10.5 MBD throughout 1985 was examined for the forecast. Depending on what is assumed about oil production in nondisrupted nations and oil inventory behavior, prices could increase by as little as $10 per barrel or by more than $50 per barrel. The disruption causes GNP to decline 1-4 percent in 1985, 1-6 percent in 1986, and 1-3 percent in 1987.

Contributed by the Energy Modeling and Economic Research Department of Edison Electric Institute.

REVIEWS

FINANCIAL REVIEW

ELECTRIC OPERATING INCOME UP 11.8 PERCENT IN 1983; CWIP GROWTH RATE SLOWS SIGNIFICANTLY

Total electric operating revenues of the investor-owned electric utility industry rose 6.6 percent in 1983 to $108.4 billion compared to $101.7 billion in 1982, while electric operating expenses were up 5.5 percent to slightly more than $88 billion. The net result was an 11.8 percent increase in electric utility operating income to $20.4 billion.

Earnings per share for the industry increased 6.9 percent in 1983 to $3.07 as a recession-induced earnings decline in the first quarter was offset by strong third- and fourth-quarter increases, although the impact of extraordinary items, such as plant cancellations, served to suppress both 1983 annual and fourth-quarter earnings. The return on average common equity, using net income before extraordinary items, was 14.5 percent in 1983, up from 13.5 percent (revised) in 1982.

Although operating revenues increased by only 3 percent during the first six months of 1983 over the same period in 1982, primarily because of mild winter temperatures and the continued effects of the recession, soaring summer temperatures and a strengthened economy supported a nearly 11 percent increase for the second half of the year.

Declining fuel prices during the first and second quarters of the year resulted in an overall 2.6 percent decline in fuel expenses in 1983, while other operation and maintenance expenses increased 8.4 percent, the lowest annual rate of increase in 16 years. The slowdown in the growth of operation and maintenance costs reflects lower inflation and continued cost containment plans in effect throughout the industry.

Interest Coverage Improves

Interest coverage—that is, the ratio of operating income to debt charges—before taxes and with allowance for funds used during construction (AFUDC) was 3.03 times compared to 2.73 times in 1982. The improvement in interest coverage resulted in large part from a 20 percent increase in AFUDC. In addition, gross interest expenses increased only 4.6 percent, reflecting lower interest rates and a 22.2 percent decrease in short-term debt. During the fourth quarter of 1983, interest coverage was 2.81 times, ranging for individual companies from 1.58 to 4.88 times. The average interest coverage during the 1982 fourth quarter was 2.44 times.

Despite the apparent improvement in the industry's coverage ratios, many companies continue to struggle with insufficient ratios. The existence of these low coverages, as well as the uncertainty of the recovery of investments and the ability to earn a return on them, was responsible for the downgrading of bond ratings of 16 companies through the first three-and-a-half months of 1984, in contrast to 16 downgradings during all of 1983.

Extraordinary Items Depress Earnings

The contribution to net income provided by extraordinary items decreased from $121 million in 1982 to a loss of $293 million in 1983, adding 3 cents per share to 1982 earnings and reducing 1983 earnings by 6 cents per share. Seventy percent of the extraordinary losses occurring in 1983 were charged to fourth-quarter income, reducing earnings per share in that quarter by 4 cents. Earnings per share before extraordinary items increased 10.2 percent in 1983 over 1982 and 26.8 percent in the fourth quarter of 1983 compared to the same period in 1982.

Table 1

Investor-Owned Electric Utility Industry Statement of Income
For periods ending December 31, 1983 and 1982 (Unaudited) (Millions of Dollars)

	Quarter Ending December 31,			Year Ending December 31,		
	1983	1982	% Change	1983	1982	% Change
Total Electric Operating Revenues	$26,782	$24,104	11.1	$108,420	$101,693	6.6
Electric Operating Expenses						
Fuel	$8,711	$8,384	3.9	$35,660	$36,627	(2.6)
Other Operation & Maintenance	6,988	6,302	10.9	26,682	24,616	8.4
Depreciation & Amortization	2,142	1,916	11.8	8,209	7,588	8.2
Taxes Other Than Income Taxes	1,926	1,728	11.5	7,816	7,151	9.3
Income Taxes (Federal & Other)	683	513	33.0	3,308	3,568	(7.3)
Provision for Deferred Income Taxes	1,382	654	111.3	4,501	1,587	183.6
Investment Tax Credit Adjustment, Net	35	357	(90.2)	1,840	2,298	(19.9)
Total Electric Operating Expenses	$21,867	$19,854	10.1	$88,016	$83,435	5.5
Electric Operating Income	$4,915	$4,250	15.6	$20,404	$18,258	11.8
Other Utility Operating Income	302	133	127.4	1,195	1,113	7.4
Total Utility Operating Income	$5,217	$4,383	19.0	$21,599	$19,371	11.5
Other Income	454	218	108.5	1,711	1,831	(6.5)
Allowance for Other Funds Used During Construction	1,313	1,123	16.9	5,028	3,889	29.3
Total Income Before Interest Charges	$6,984	$5,724	22.0	$28,338	$25,091	12.9
Interest on Long Term Debt	$3,223	$2,951	9.2	$12,468	$11,483	8.6
Other Interest Expenses & Charges	296	332	(11.0)	1,117	1,500	(25.6)
Allowance for Borrowed Funds Used During Construction	(789)	(755)	4.5	(3,136)	(2,917)	7.5
Net Interest Expenses & Charges	$2,730	$2,528	8.0	$10,449	$10,066	3.8
Net Income Before Extraordinary Items	$4,254	$3,196	33.1	$17,889	$15,025	19.1
Extraordinary Items	(204)	39	(623.4)	(293)	121	(342.3)
Net Income	$4,050	$3,235	25.2	$17,596	$15,146	16.2
Preferred Dividends Declared	715	623	14.8	2,787	2,502	11.4
Net Income Available for Common	$3,335	$2,612	27.7	$14,809	$12,644	17.1
Common Dividends Declared	2,670	2,284	16.9	10,264	8,968	14.4
Retained Earnings	$665	$328	102.8	$4,545	$3,676	23.6
Earnings Per Share*	$0.67	$0.57	17.7	$3.07	$2.87	6.9
Common Dividends Per Share*	$0.54	$0.50	7.7	$2.13	$2.04	4.4

NOTE: The income statement is a "net" statement since the duplicative effect of including resale revenues by one investor-owned electric utility to another has been eliminated.
*Based on average shares outstanding as reported to EEI by survey respondents and adjusted for stock splits.

Table 2
Investor-Owned Electric Utility Industry Balance Sheet
As of December 31, 1983 and 1982 (Unaudited) (Millions of Dollars)

Assets	1983	1982	% Change
Utility Plant*			
Utility Plant (Including Nuclear Fuel)	$273,314	$254,542	7.4
Less Accumulated Depreciation	76,534	73,605	4.0
Less Property-Related Accumulated Deferred Income Taxes	3,960	3,380	17.2
Total	$192,820	$177,557	8.6
Construction Work in Progress	98,356	90,320	8.9
Net Utility Plant	$291,176	$267,877	8.7
Investments	7,007	6,656	5.3
Current Assets	32,628	31,799	2.6
Deferred Debits	10,108	7,486	35.0
Total Assets	$340,919	$313,818	8.6
Capitalization & Liabilities			
Capitalization			
Common Stock	$74,527	$67,796	9.9
Retained Earnings	34,924	30,984	12.7
Preferred Stock	30,571	28,616	6.8
Long-Term Debt	131,639	123,692	6.4
Total Capitalization	$271,661	$251,088	8.2
Current Liabilities			
Short-Term Debt	$5,273	$6,780	(22.2)
Long-Term Debt Due Currently	3,965	3,319	19.5
Other Current Liabilities	24,584	23,257	5.7
Total Current Liabilities	$33,822	$33,356	1.4
Deferred Credits			
Accumulated Deferred Income Taxes	$18,782	$14,930	25.8
Accumulated Deferred Investment Tax Credits	11,806	10,408	13.4
Other Deferred Credits	4,848	4,036	20.1
Total Deferred Credits	$35,436	$29,374	20.6
Total Capitalization & Liabilities	$340,919	$313,818	8.6

* Includes other utility plant of combination gas and electric companies.

REVIEWS

AFUDC Increases; CWIP Increase Slows

AFUDC as a percent of net income available for common increased to 55.1 in 1983 from 53.8 in 1982. During the fourth quarter of 1983, AFUDC accounted for 63.0 percent of net income available for common compared to 71.9 percent during the fourth quarter of 1982. The magnitude of AFUDC earnings during the fourth quarter of 1982 was more the result of low fourth-quarter income from operations because of the mild winter weather than from a sudden surge in AFUDC.

Construction work in progress (CWIP) increased 8.9 percent from December 31, 1982, to December 31, 1983. CWIP had increased at an average annual compounded rate of 19 percent since 1970. As a result of its slowing growth rate, CWIP, as a percent of net plant in service at year-end, was only slightly higher for 1983 than for 1982 (51.0 percent vs. 50.9 percent), evidence that the expected peaking in construction expenditures forecast for the industry may be at hand.

Common equity as a percent of total industry capitalization increased from 39.3 in 1982 to 40.3 in 1983. Long-term debt decreased slightly from 49.3 percent to 48.5 percent of total capitalization. Estimates are that the industry generated 39.7 percent of its cash construction expenditures internally, up from 32.2 percent in 1982.

In conjunction with the slowing rate of increase in construction expenditures, the increase in total industry capitalization slowed in 1983 to its lowest rate since 1978. At the end of 1983, capitalization was 8.2 percent or $20.6 billion higher than at the end of 1982. This compares with the 10.1 percent or $23.0 billion increase in total capitalization that occured between December 31, 1981, and December 31, 1982.

Tables 1 and 2 are based on unaudited reports received from electric utilities. The utilities account for about 95 percent of the industry's revenue from sales to ultimate customers and 94 percent of the industry's total assets. The data was expanded to represent the entire industry. EP

Contributed by the Finance Department of Edison Electric Institute.

REGULATORY REVIEW

TAX NORMALIZATION FOR UTILITIES

By Marie Mastin Newman

Electric utility customers benefit significantly from an accounting procedure used in ratemaking known as tax normalization, which utilities currently use in conjunction with the investment tax credit (ITC) and accelerated deductions for depreciation (ADFD). This practice results in increased capital funds available to utilities for investment purposes at no cost to the consumer, decreased finance costs, and lower electricity prices for customers. It helps to promote equality among all generations of ratepayers of a particular facility by not granting favorable treatment to one generation at the expense of another. And it acts as a stimulus to the economy in accordance with the intent of Congress by providing funds for expansion and modernization of facilities and equipment, thus helping to create additional jobs.

Tax normalization in conjunction with the tax incentives of ADFD and the ITC has been common practice among utilities for many years and has been mandated by Congress in various forms since 1969, most recently in 1981. Now, however, utilities and their customers are in danger of losing the benefits of this practice. Legislation currently being considered by Congress would elimi-

nate the mandatory requirement for normalization of the ITC and ADFD and would allow regulatory bodies, after holding hearings and establishing a least-cost energy plan, to determine what treatment tax benefits will have. The bill, H.R. 4923, the Phantom Tax Reform and Least Cost Electric Energy Planning Act of 1984, was introduced in February by Congressman Tom Harkin (D-IA) and has been referred jointly to the House Ways and Means Committee and the House Committee on Energy and Commerce.

Funds arising from normalization are an essential part of the financing of the investor-owned electric utility industry. The end of normalization would have a significant effect on company cash flows, raising costs of capital and the cost of service to customers and threatening future supply reliability. Particularly at a time when the financial situation of a number of companies is fragile, retention of the present tax normalization provisions of the Internal Revenue Code is imperative.

The stakes are high because the dollar figures are high. At the end of 1983, for example, the balance sheets of investor-owned utilities in the U.S. showed a pool of cumulative capital funds worth $34 billion because of tax normalization of the ITC and ADFD. These deferred funds will have to be paid out eventually, but in the meantime represent a no-cost loan from the government that utilities can use to assist in the financing of capital expenditures. Without normalization, utilities would have $34 billion less in capitalization and would be required to seek this same amount in financing from outside sources with attendant financing costs (interest or dividends). It is estimated that it would cost $6 billion annually to finance $34 billion and these charges would be passed on to customers in the form of higher prices for electricity. As it stands, these are no-cost loans from the U.S. Treasury. Additionally, without normalization, investments in utilities are riskier, therefore financing costs would be at higher rates. This would also increase the cost of electricity to the consumer.

To understand how normalization works to create the pool of capital funds, it is necessary to understand some key points. The first is the nature of the tax incentives involved. The ITC allows a business to subtract a percentage of its capital investment directly from its tax liability. At the present time this percentage ranges from 4 to 10 percent and is usually taken in the first year that the investment is made. It represents a tax savings on the investment taken directly off the taxpayer's bill.

Depreciation is a business expense representing an estimate of how much of an asset is used up during a particular time period. Depreciation is like other business expenses; it takes the form of a deduction for the expenses from revenue. Depreciation can be taken at several rates. Straight line depreciation is an equal allocation of depreciation expense each year over the life of an asset. Accelerated depreciation, or accelerated deductions for depreciation, increases the depreciation expense over straight line depreciation early in the life of an asset thereby allowing lower taxes in early years. The situation reverses itself in the later years of an asset when the depreciation expense decreases and more taxes are paid. The net effect is that the same amount of taxes are paid over the life of an asset with ADFD as with straight line depreciation. However, ADFD allows businesses temporary use of the money that would otherwise go to pay taxes in the early years. By doing so, it takes advantage of the time value of money. As the reasoning goes, a dollar today is worth more than a dollar five years from now because of inflation and because that dollar can be invested and generate retained

earnings. This is what Congress intended—to allow businesses tax incentives to create capital to create jobs and increase productivity.

The practice works as intended with unregulated businesses that have the discretion to use the increased capitalization as they see fit. However, for regulated companies such as utilities, the situation is not as straightforward. Utility rates are set by regulatory bodies and are based on a utility's cost-of-service. Taxes are part of that cost-of-service and when the tax expense is lower in any given year (as it is when the ITC and ADFD are taken), a utility's revenue requirements from its customers are lower. It follows that given this situation a regulatory body would in turn lower rates. And without special stipulations such as normalization of tax benefits, this is, in effect, what would happen. Lower taxes (because of increased tax benefits) would be used to reduce a utility's rates in the year that the tax incentives are taken. Thus, the tax benefits of ADFD and the ITC would be passed on to the customer in the form of lower rates rather than being retained by the utility for investment as Congress intended.

This situation is what occurs with *flow through* accounting, the counterpart to *normalization* accounting. In flow through accounting, the ITC and ADFD benefits flow through immediately to the consumer in the form of reduced rates in the short run. As a result, the customers in the first or early years of a property enjoy a temporary advantage over future customers who must pay higher rates in later years when the tax benefits run out. Flow through accounting has been described as the accounting approach that gives the entire benefit today and leaves nothing for the next generation. If electric utility property is in service today as well as in a decade or two from now, and all the benefits are taken in the first year, or early years, nothing will be left for tomorrow's ratepayers.

Normalization accounting seeks to address this inequity while at the same time preserving tax benefits for capital investment by spreading the tax expense and benefits evenly among all generations of taxpayers who benefit from the electric utility property, so that each pays a fair and equal share. When a utility uses normalization accounting, it makes a distinction between the tax expense reported for accounting/ratemaking purposes and that reported for tax purposes. With normalization, the utility takes the tax benefits of the ITC and ADFD for tax purposes, but spreads these benefits evenly over the life of the property for accounting and ratemaking purposes. In other words, the utility pays taxes at the lower level dictated by the ITC and ADFD and realizes tax savings and a temporary loan, respectively, but instead of passing these directly through to the customer in the form of lowered rates in the early years, it prorates the savings over the life of the asset for ratemaking purposes. The difference between the tax expense for tax purposes and the tax expense for ratemaking purposes creates the deferred taxes. For example, if $2 is paid to the U.S. Treasury for tax purposes and $3 is collected from the customer for ratemaking purposes, the difference of $1 constitutes the deferred taxes. These taxes will eventually have to be paid to the government, but in the meantime they represent a no-cost loan from the government that the utilities can use for capital expenditures. This advantage is particularly significant for utilities—the most capital-intensive industry in the country. According to the U.S. Department of Energy, construction expenditures of the investor-owned utility industry now represent 20 percent of all new industry construction in the United States. These expenditures create jobs and

stimulate other investment. Also, many capital expenditures of utilities are not as affected by recessions as are those of other industries because of their long construction periods. Thus, utilities are making investments at a time when they are most needed.

A controversy has existed for many years concerning flow through vs. normalization accounting methods because of the political ramifications of their application. Flow through accounting has been advocated by those who believe that the public is best served by keeping utility rates as low as possible in the short run. Normalization is advocated by those who believe that tax incentives should aid in capital formation for investment purposes, resulting in the development of jobs. Normalization advocates also point to the lower cost of money being charged to customers and to the more equitable treatment of all customers who use an asset over its life.

Those who oppose normalization often argue that the temporary use of cash arising from these tax incentives encourages unnecessary investment in power plants. This argument ignores the reality of the regulatory process, the lack of adequate returns in the utility capital market, and the risks involved in the construction of major power plants. Tax benefits alone would never be enough to encourage a utility to embark on construction of a new power facility. The cost is too great and the rewards are simply not high enough to justify the risk of additional investment for plant construction unless there is a very definite need for it.

Before normalization was mandated by Congress, a significant number of state commissions had prescribed normalized accounting for their utilities. Were H.R. 4923 to become law, commissions might still retain this beneficial method of accounting. However, there are very real political pressures on commissions to keep the cost of electricity low in the short run, particularly in the present environment. The risks are therefore great that normalization might very well be sacrificed for short term interests in many jurisdictions were this legislation to succeed.

Marie Mastin Newman is a Washington, D.C., writer and communication consultant.

BOOK REVIEW

REGULATION AND THE COURTS: THE CASE OF THE CLEAN AIR ACT

R. Shep Melnick
The Brookings Institution, 1983
Washington, D.C. 404 pp.

By Robert L. Baum

The major role the courts were to play in the implementation of the 1970 Clean Air Act was not only predicted at the time of the Act's passage, but also considered by the authors of the law to be an integral part of that implementation. Years of neglect and a growing body of information concerning the adverse effects of air pollution combined with the politics of the late 1960s to insure the enactment of an ambitious remedial law. However, in many cases, there were large gaps between the law's goals and society's ability and willingness to implement them.

Crucial to this situation was the theory of the Act itself: the establishment and achievement of health-related national ambient air quality standards. Proponents of the Act saw the political as well as the real air quality benefits of casting the Act as a public health measure rather than as a technology-based control program. But concrete information about health effects and how to achieve clean air was at best incomplete and in some cases virtually nonexistent.

Nevertheless, Congress, reflecting the strong public perception that more delay was unacceptable, not only enacted

a comprehensive law, but established strict time deadlines for its implementation. These deadlines were touted as necessary because of the seriousness of the air pollution problem. However, a more practical reason was the belief of Congress that without such deadlines, the administrative agencies would not implement the Act effectively or expeditiously. These deadlines applied to actions of the Environmental Protection Agency (EPA), e.g., establishing national ambient air quality standards; the states, e.g., the submission of implementation plans to meet the standards; and, of course, to the sources of pollution that would have to comply with the resulting emission standards.

Persons most knowledgeable in the field, and thus most heavily involved in drafting the legislation, were aware of the gap between the goals of the Act and the nation's ability to achieve them. But the politics of the time as well as the widespread failure of potential critics to recognize the full impact of the law insured that no strong objections were made. Those who were concerned about how the Act's provisions would be implemented were satisfied that its overall beneficial effects outweighed their concerns, and/or that the solutions to the implementation problems, although not yet specified, would be impartial because the task of resolving these issues was left clearly to the federal courts.

In addition to the normal court review of agency actions, Congress insured broader court involvement in Clean Air Act issues by enacting a citizens' suit provision in the law designed to both enforce emission standards and deadlines and to require EPA to fulfill its responsibilities in a manner consistent with the Act's protective criteria. Theoretically, the latter suits were to be brought against EPA only when necessary to require the Administrator of EPA to perform "nondiscretionary" acts.

Authorizing environment-oriented private attorneys to invoke court orders to insure compliance with the Act accomplished two purposes. First, it comforted Congress that the perceived financial and organizational advantages enjoyed by business interests over private citizens when both parties are involved in litigation would be balanced. Second, and more relevant to this discussion, it allowed the Congress to finesse many difficult questions with the confidence that politically independent courts would resolve them in a manner consistent with the purpose of the Act.

In short, the gap between the promise of the Clean Air Act and the practical difficulties in achieving that promise was left to be bridged by the courts. It was clear that the cases arising under the Act would involve more than run-of-the-mill, discrete questions of statutory interpretation. Instead, the courts would have to begin making policy where Congress left off.

In *Regulation and the Courts, The Case of the Clean Air Act*, R. Shep Melnick describes in great detail the role of the federal courts in fulfilling this role.

To illustrate the courts' involvement in the implementation of the Act, Melnick selects six case studies. The issues involved in these cases are both the most important and the most interesting that have arisen under the Act. As a group, they reveal the full scope of the courts' involvement, ranging from the courts' review of EPA's air quality standards, a traditional function of the court performed somewhat untraditionally, to the courts' decision that the Act required the EPA to prevent the significant deterioration of air quality. Both cases merit a brief discussion.

National Air Quality Standards

In the air quality cases, the courts ostensibly were performing a routine function—providing statutory interpretation. But the complexity of the questions involved in ambient air quality standards led to an unusual if not unprecedented court review of medical and scientific evidence. Melnick believes that the courts' decisions

regarding air quality standards have tended to cause EPA to "err on the side of over-protection" in setting standards. He attributes this error, at least in part, to the courts' refusal to permit EPA to consider costs, and to the courts' view of themselves as the only bodies free of political pressures and thus under a special duty to protect the health of private citizens.

While these observations are probably correct, it is also worth pointing out that the courts' approach to air quality standards is not merely consistent with the policy of the Act, but legally mandated. The health standards are simply health standards. Technical and economic considerations are irrelevant to the questions of a pollutant's health effects. Faced with a statute and legislative history that excludes consideration of costs and requires more rather than less stringency where uncertainties exist, the court—usually the D.C. Court of Appeals—had little choice. The fact that standards adopted without regard to practical considerations might not be achievable in accordance with the other provisions of the Act could not be used as a legal basis for a different interpretation. Moreover, as Melnick points out, the problems of implementation usually arose in subsequent cases, most often in other courts. In those cases, as the courts were faced with factual problems, a way was usually found to accommodate the competing interests. Three of the case studies Melnick presents demonstrate the courts' obvious search for a "practical" result.

One can argue that the courts' view of the need for stringency in cases involving air quality standards and flexibility in the enforcement matters is consistent with the theory, if not always the language, of the Act, and, in fact, was the result intended by Congress.

Ambient air quality standards were a means of authoritatively informing the public of the level of air quality necessary to protect health. By comparing these standards with existing air quality, interested persons could understand the magnitude of the problem. On the other hand, despite the rhetoric accompanying the passage of the Act, Congress did not expect, desire, and, in fact, would not stand for wholesale closing of sources, or the extreme disruption envisioned in some of the Act's legislative history, e.g., severe restrictions on the use of automobiles.

Preventing Significant Deterioration

Melnick's belief in the courts' view of themselves as protectors of the public health is supported by the litigation giving birth to the doctrine of prevention of significant deterioration of air quality (PSD).

In 1982, motivated mostly by the fear of large sources of air pollution locating in the areas of the western United States where air quality was good, the Sierra Club sued EPA in the D.C. District Court. The complaint alleged that under the Clean Air Act the Administrator of EPA had a non-discretionary duty to disapprove any state Clean Air Act implementation plan that permitted the "significant deterioration" of air quality. Within a few weeks, the judge issued a brief handwritten opinion agreeing with the interpretation urged by the Sierra Club. Thus, as Melnick observes, "PSD was born in the courtroom and has resided there almost constantly for the past decade."

The case was affirmed by the D.C. Court of Appeals without an opinion, and the U.S. Supreme Court split four to four, leaving the decision intact. The District Court opinion did not define "significant deterioration" nor did it hint at the type of regulatory program necessary to implement the decision. Since there was no Congressional guidance on the subject—the Act does not use the term—EPA was faced with developing a comprehensive and controversial program with neither judicial nor legislative guidance. As Melnick points out, the court had "in effect replaced the Clean Air Act's uniform national ambient air quality standards with a multiplicity of standards based on previous

air quality levels, not on health or welfare effects."

Despite the fact that subsequent to the decision EPA embraced, and Congress codified, the concept of PSD, the value and wisdom of the courts' action in the Sierra Club's case is questionable. For the purpose of this review we can disregard the fact that "... [e]ven those legal commentators who applaud the ... decision admit that its legal underpinnings are so weak as to require justification on policy grounds." The legal considerations are important only to illustrate that in this case the court had a choice. The more important question is whether PSD or other significant national policies, including those with substantial public support, should be imposed in this fashion. Melnick seems to approve of the result and believes that only the courts could have made this tough decision.

Developing and Implementing Policy

The four remaining case studies in the book are interesting examples of the judiciary coping with basic interpretations of the Act as well as its basic policies. While the role of the courts in these issues is important, more instructive is the overall description of the issues and the policies underlying the positions of the various parties, for it is the description of the interplay of the combination of such forces that ultimately shapes public policy.

An interesting example of competing interests in policy development is described in the case involving the dispute over the use of "dispersion" or "intermittent control systems" to meet ambient air quality standards. Since air quality is measured at ground level, in some cases ambient standards could be met without reducing emissions if stack heights could be increased to disperse emissions and lessen their impact in certain areas. In other cases, intermittent control systems, i.e., temporarily curtailed or terminated operations to reduce emissions, could achieve the same result.

Section 110 of the Clean Air Act required that implementation plans to meet ambient standards must include enforceable emission limitations and such other measures as necessary to insure attainment of the standards. Since there was no definition of any of these terms, a legitimate legal issue existed. As a policy matter there was no doubt that, in a general sense, implementation of the Clean Air Act would reduce emissions of pollutants. However, those concerned with total atmospheric loading believed the Act required constant emission reduction in all cases. The opposing view was held that if dispersion and intermittent control techniques could achieve air quality at ground level, health and welfare was protected as required by the Act.

Without detailing the course of this issue through EPA, the courts, and later through the Congress, it is worth noting that the issue is not entirely a clear-cut philosophical or legal question. It involves a number of extremely complex technical issues such as proper stack height, reliability of intermittent control systems, and the feasibility of such systems meeting compliance standards. As Melnick points out, in deciding a complex technical issue on the basis of legal arguments, the courts revealed their "primitive understanding of the issues before them." Nevertheless, the courts decided the issue in accordance with the perceived preferences of the authors of the Act: dispersion and intermittent control systems were not the appropriate way to achieve the Act's goals.

Although it does not detract from the usefulness of the book, Melnick does not make a strong case for changing the system. This is true despite his recognition of the problems involved in leaving to the courts the task of filling the gaps among policy goals, technical capabilities and costs, and the "resources the political community is willing to expend." Melnick accepts the fact that the judiciary will continue to be an active participant in these

matters, and a short section on "reform" considers only changes to the way courts consider these cases.

More specifically, Melnick lists a number of possible changes. Included is Judge Harold Leventhal's suggestion that judges hire science clerks as well as law clerks. The concept of courts that specialize in scientific and/or environmental cases, which has received some consideration, is also noted. But the author concludes that what is needed is better understanding by the judiciary of the administrative process. The premise is that judges must know more about the problems that they face, the policy behind each legal position, and the administrative feasibility of implementing their orders.

More to the point of obvious deficiencies in the system, *Regulation and the Courts* raises a number of questions about the role of the judiciary in making policy. First, while no one can argue that judges should not attempt to fully understand the consequences of their decisions, those consequences cannot and should not always dictate decisions. During the oral argument of the Sierra Club case before a D.C. Circuit Court of Appeals panel, one of the judges asked the Department of Justice lawyer if it was not true that it was easier to prevent degradation of air quality before it occurred than to clean it up afterwards. When the attorney simply said yes, without further explanation, one could sense all of the judges mentally deciding the extremely significant policy question involved in the case. Clearly in that instance, judges more aware of the ramifications of their actions might have either ruled differently or provided written guidance regarding implementation of their decision.

In his discussion of how courts might improve their ability to deal with the types of cases he describes, Melnick assumes that Courts will continue to decide these cases. While this assumption is unquestionably correct, some of the cases in the book at least raise the possibility that courts are not the best forum for resolving complex policy issues.

Clearly courts are accustomed to dealing with enforcement cases. The fact that some enforcement cases may result in precedents that are difficult to apply to other factual situations is recognized. However, as I believe the Clean Air experience has proved, the agencies and the courts can "muddle through" the enforcement problems. In the setting of standards, courts are on familiar ground and have performed well. The judiciary is generally credited with improving the agency's performance in setting standards. Despite the technical complexity of the standards cases, Melnick points out that the "number of occasions on which judges have misread scientific evidence is extremely small" and that judges "appear to recognize their own limitations" when considering such cases.

Of more interest is the courts' role in basic policy questions such as PSD and dispersion. The courts' actions on these matters is more than filling the interstices. Both of these cases involved basic policy decisions that defined the scope of the air pollution program and the method by which its goals were to be achieved. As the author points out, the courts' political independence insures some degree of objectivity in resolving these types of issues. However, it is by no means clear that this objectivity results in better decisions. Whether or not these issues should be resolved by courts is a question worth addressing. If they should not, a mechanism for permitting, if not requiring, the judiciary to refer such questions to the Congress might be considered. The issue is, of course, a difficult one and not truly within the scope of the book or this review. But a system that requires two or three levels of courts in the District of Columbia to struggle with basic policy issues involving the Congressional intent behind a few words in a statute, while the drafters of those words watch from a few blocks away, might well be reexamined.

Robert Baum is Senior Vice President and General Counsel for Edison Electric Institute.

REVIEWS

TECHNOLOGY REVIEW

ELECTRON-BEAM FLUE GAS TREATMENT

How can the emissions of coal-fired plants be reduced in a more cost-effective manner than they already are? An innovative electron-beam flue gas treatment process being tested at Indianapolis Power & Light Company's E. W. Stout generating station may hold the answer.

The process, designed by Ebara International of Japan, promises several advantages over present scrubber technology including simultaneous removal of sulfur and nitrous oxides; enhanced removal of particulates; low operating costs; no slurry recycling, sludge disposal, or stack gas reheating; easy process control and good load-following capability; and conversion of pollutants to agricultural fertilizer.

The test project, which is being conducted by Ebara, is sponsored by Indianapolis Power & Light and other member utilities of the Indiana Electric Association, the Indiana Department of Commerce, Indiana Energy Development Board, AMAX Coal Company, CF Industries, the U.S. Department of Energy, and Ebara.

"The project holds great promise in two very important public policy issues—how we can make it possible to mine and sell more high-sulfur Indiana coal, and how we can make sure emissions in general are free from nitrogen and sulfur oxides," Indiana Lieutenant Governor John Mutz said at ground breaking ceremonies held earlier this year.

Electron-beam radiolysis works like this: Flue gas is cooled in a spray cooler so the temperature of the gas is at a controlled level. Ammonia is then injected into the gas stream as it proceeds to the process building. There it is diverted into a large open chamber where two electron-beam guns irradiate it, forcing the pollutants in the flue gas to react with the ammonia to form a powdered by-product containing ammonium sulfates and nitrates. This by-product is then collected in either a bag house or electrostatic precipitator and conveyed to a storage bin. Trucks then move it to a fertilizer facility for processing into a salable fertilizer.

"The entire process uses much less water than our present scrubber systems at other plants," explained Jeff Antonetti, General Engineer in Indianapolis Power & Light's Environmental Engineering Department, who is acting as liaison for the company with representatives of Ebara. "Since the system produces a salable fertilizer it has the potential to be less costly than the wet scrubbers the company now operates."

Presently, Indianapolis Power & Light uses a wet flue gas desulfurization system on Unit 3 at its Petersburg generating station that can remove approximately 80 percent of sulfur oxides from emissions. The electron-beam flue gas treatment process to be tested on Unit 6 at E. W. Stout is a dry process that has effectively removed 90 percent of sulfur oxides and 80 to 90 percent of nitrous oxides from emissions released by a smaller oil-fired boiler at a steel plant in Japan.

Ebara President Norman Frank believes electron-beam radiolysis to be very competitive with present emission control technologies. According to Frank, capital costs for the process should be below $200 per kilowatt. "The process," Frank says, "should be ready for commercialization within a year, and we are prepared to scale-up to 100 to 200 megawatts. There is a lot of interest in the process, not only in the United States, but also in several other countries. In some developing countries, for example, the fertilizer by-product will be just as valuable as the emission reduction capability. A developing country could retrofit an existing power plant rather than build a very expensive large scale fertilizer plant."

Construction of the process building at the E. W. Stout facility began in June of 1984 and is scheduled for completion this October. When testing begins, Ebara will pull five percent of the flue gas off for processing. Testing will continue for 12 to 15 months.

Contributed by the Information and Publishing Services Department of Edison Electric Institute.

MEETINGS

EDISON ELECTRIC INSTITUTE

August 20–22
Training Directors' Institute
Minneapolis, Minnesota
Frances Palladini

August 23–24
Communication Executive Advisory Committee
Boston, Massachusetts
William Brier

September 4–7
Health Physics Committee
St. Louis, Missouri
Ken Travis

September 10–12
Engineering & Operating Division Computer Forum
Atlanta, Georgia
Martin Gordon

September 10–14
A.G.A.-EEI General & Plant Accounting Committees
Nashville, Tennessee
George Brown

September 11–13
Quality Assurance Committee
Minneapolis, Minnesota
Suzanne Phelps

September 16–19
Rate Research Committee
Minneapolis, Minnesota
David Owens

September 17–18
Construction Committee
Milwaukee, Wisconsin
Eric Haskins

September 17–19
A.G.A.-EEI Budgeting & Financial Forecasting Committees
Charleston, South Carolina
Lowell Klosky

September 17–19
Meter & Service Committee
Denver, Colorado
David Soffrin

September 17–19
Fire Protection Committee
Williamsburg, Virginia
James Evans

September 18–21
Economic Development Committee Meeting/Workshop
Lexington, Kentucky
Charles Taylor

September 18–21
Residential Subject Area Committee/Workshop
Minneapolis, Minnesota
Robert Griffin

September 19–21
Environment & Energy Committee
Fort Worth, Texas
Victoria Hull

September 20–21
Electronic Information & URAP Services Workshop
San Francisco, California
Norman Jenks

September 24–26
Commercial-Industrial Subject Area Committee/Workshop
Dallas, Texas
Charles Taylor

September 27–28
USWAG Policy Committee
Boston, Massachusetts
John Novak

October 1–3
Safety & Industrial Health Committee
San Diego, California
Melodye Turek

October 1–3
A.G.A.-EEI Internal Auditing Committees
Boston, Massachusetts
Marshall Baker

October 1–3
Nuclear Operations Committee
Phoenix, Arizona
Suzanne Phelps

October 1–3
Prime Movers Committee
St. Louis, Missouri
James Evans

October 1–3
Street & Highway Lighting Conference
Kansas City, Missouri
Charles Taylor

October 2–4
Claims Committee
Boston, Massachusetts
Robert Baum

October 2–5
Risk Management Committee
Boston, Massachusetts
Ted Gradin

October 3–4
Corporate Planning Committee
New Orleans, Louisiana
Sue Lerner

October 4–5
Interconnection Arrangements Committee
Baltimore, Maryland
Martin Gordon

For further information on any of the meetings listed, call the contact person indicated at 202/828-7400.